CALIFORNIA ENERGY COMMISSION

Interconnection in California (Connecting Distributed Generation to the Grid)

(REPORT DATE: JUNE, 1999)

CONSULTANT REPORT

OCTOBER 2000
P700-00-010

STATE OF CALIFORNIA 1975 2000 ENERGY COMMISSION

Gray Davis, *Governor*

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Interconnection in California
Connecting Distributued Generation to the Grid

A. Introduction

The competitive power industry is introducing alternatives to the traditional integrated utility. A new market for on-site generation is emerging, driven by electric industry restructuring, the unbundling of electric services, and increasing customer awareness of energy costs and energy service options. Generally referred to as Distributed Generation (DG), this new market will entail the installation of small modules of power (typically less than 20 MW in size) at customer sites throughout the electrical distribution grid. An important subset of distributed generation is Combined Heat and Power (CHP), an application of on-site generation that efficiently and cleanly provides both electricity and useful thermal energy to the user. [1]

Key to the ultimate market success of CHP and other forms of distributed generation is the ability to safely, reliably and economically interconnect with the existing utility grid system for supplemental and backup power needs. Before investing in CHP and other distributed generation technologies, customers will need assurance that they are: 1) allowed to connect to the grid 2) at a reasonable cost. It is not always possible to give those assurances today. Non-standardized, out-dated, and in some cases, overly stringent interconnection requirements hamper the wide spread deployment of distributed generation technologies. Interconnection requirements vary by utility and may not be based on state of the art technology or data. Compliance often requires custom engineering and lengthy negotiations that add cost and time to system installation. These requirements can be especially burdensome to smaller systems under 1 MW in size. Non-standardized requirements also make it difficult for equipment manufacturers to design and produce modular packages. Whether the technology is a micro-turbine, fuel cell, industrial gas turbine, or engine-generator set, the lack of consistent interconnection requirements hampers the efforts of manufacturers to realize economies of scale and discourages the economic business case for on-site generation.

Utilities have legitimate concerns about interconnection, including safety of line personnel, the safety of the equipment and the reliability of the distribution system. They are concerned about the potential impacts on system stability caused by increased deployment of distributed generation on the grid. Because of their different concerns and different bases of knowledge, conflicts between utilities and manufacturers over interconnection are not unusual.

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[1] Interconnection issues facing Combined Heat and Power are mostly the same interconnection issues faced by the whole class of Distributed Generation technologies. Where the issues of CHP and power-only generation diverge, note will be made in the text of the divergence. Otherwise, distrubuted generation, including CHP, will be referred to throughout this paper as "DG" or "on-site generation". Occasional references will be made to Distributed Resources, or DR (which include end user energy efficiency and load management along with the gamut of DG technologies) when that term is part of an existing study or organization, or when the broader sense is intended.

The conflict has roots in the transmission and distribution system infrastructure, and its surrounding regulations and policies. Until recently, utilities have been vertically integrated monopolies, producing electricity at central generating stations and delivering it one way to end users. DG in a competitive market complicates this model, requiring the power delivery grid to do a different job than it was designed to do. In the words of Kurt E. Yeager, President & CEO of the Electric Power Research Institute (EPRI), DG is "transforming today's radial, electromechanically controlled grid into an electronically controlled, open-access, smart network." Specific interconnection barruers that impact the development of CHP include:

Distribution System Design Limiatations: The electric distribution system was not designed to operate with DG backfeeding significant amounts of power into the grid. The distribution system was designed for one-way power flow. Conductor and equipment ratings are based on load and fault contributions from the utility system only. Protection and operation is based on known utility-controlled (or system operator controlled) generation sources. Introduction of on-site generation adds complexity to an established well-known system, including multiple sources, two-way power flow, additional ground paths and new protection schemes.

Non-Uniform and Uncertain Interconnection Requirements: Differences in interconnection requirements among the utilities often requires different relay packages and other protective devices, adding unnecessary cost and complication to the system. Published requirements are often minimal and actual requirements are often not known until the utility completes its project review, adding uncertainty, additional costs and time delays to the process.

Cost to Implement: Because of uncertainties, inconsistencies and the resultant need to engineer interconnect requirements on an individual basis, cost of arriving at and implementing the requirements can be expensive and time consuming. This can be a significant economic hurdle for smaller CHP and other distributed generation systems.

Entitlement for Non-QF's[2]: Since PURPA was the precursor to the development of non-utility generation, its impact can be found in QF status often being a utility precondition for interconnection. Many regulated utilities' current interconnection requirements address only QF's, not non-QF's. Whether a facility is a QF or not may be irrelevant under deregulation. However, there is an interconnection entitlement restriction in operation in California today whereby non-QF's are disallowed in practice from interconnecting.

New Technologies not included: Hardware advances made in micro-processor based protective devices, as well as software innovations for system protection and

[2] To be a Qualifying Facility (QF), PURPA requires a generating facility to capture more than a minimum quantity of waste heat, and / or use a renewable fuel source.

communication and control, are not typically reflected in current published interconnection requirements.

Stand-By and Other Tariffs: Customer-sited generation requires in most cases a back-up source of power to meet load requirements during generation outages or routine maintenance periods. Utilities now charge not only for the power used, but also for the reserved generation and distribution capacity. Unreasonably high charges for these services have been barriers to on-site generation in the past.

Structure of this Paper

After a brief background on interconnection issues and concepts, this paper will cover the following in order: Interconnection issues and policies specific to California; Overview of California interconnection requirements; Technical, economic and policy barriers to California interconnection; Suggestions for overcoming interconnection barriers; and Developing an Interconnection Standard: IEEE and CADER, a look at standards development nationally and statewide; followed by References for the paper. The first two appendices were prepared as part of the effort of this paper. Appendix 1. Detailed summary of interconnection requirements; Appendix 2: Other Interconnection Efforts Outside of California; Appendix 3: New York State Standard Interconnection Requirements; Appendix 4: Texas Interconnection Standard Draft, Appendix 5: California Utility Interconnection Standards; and finally Appendix 6: California Net Metering Agreement and the IEEE PV Standard.

Background: Technical Interconnection Issues and Concepts

Stakeholders in interconnection discussions agree that the safety and reliability of the grid must not be compromised in any way. The impressive historical record of grid safety and reliability bears out legitimate issues and concerns from the perspective of the utility. The safety and reliability enjoyed in the United States is not an accident. A dedicated team of system planners, protection engineers, field technicians, and central dispatchers keep the lights on; and ensure the safety of utility workers, utility equipment, and the general public. The grid has been designed to provide bulk electricity supply, which is driven by economies of scale and long-term average cost models. The existing distribution systems are designed to have the supply on one end, and the loads along the line. It is important to ensure that generation sources not incorporated into grid design do not degrade grid integrity.

Distribution System Topology Review

A brief discussion of utility distribution system planning, design, and operation is helpful at this point, to serve as a "primer" for the interconnection analysis that follows. In general, there are three fundamentally different types of power distribution configurations in use by electric utilities. They are classified as radial, loop, or meshed – network configurations. Each has its own merits, and differs in how the distribution feeders are arranged and interconnected about a substation.

In North America, nearly all grids are operated as radial systems. The key characteristic of a radial configuration is that it has only one electrical path from the substation to the customer because they were designed for the purpose of delivering electrons to customers. The electrical power flows exclusively away from the substation and out to the customer along a single path. If this path is interrupted, the result is a loss of power flow to the customer. Radial design comprises approximately 99% of all distribution systems due to two clear advantages. It is almost always the least costly by considerable margin, and it is much simpler to plan, design, and operate. Radial systems are enormously popular in North America because their simplicity provides straightforward analysis and predictability of performance. The unidirectional power flow is absolutely certain by design. The load at each point can be easily found by simply adding up all the customer loads downstream from that piece of equipment.

In most radial systems, both the feeder and secondary system are operated as radial systems. In other words, each feeder provides definite service to all customers in its defined service area, but no where else. The opportunity for misunderstanding occurs when the term “radial system” is used as a catch-all term for the distribution grid. Most radial feeder systems are actually designed and built as meshed-networks, but are then operated radially. Opening switches at certain points throughout the physical network facilitates radial operation, so that the end result is an electrically radial configuration. The distribution planner determines the layout of the network, the size of each feeder segment in that network and where the open points should be for proper radial operation.

Radial distribution systems are inherently less reliable than loop or meshed-network systems because there is only one path between the substation and the customer. A failure from any cause generally requires a repair crew to be dispatched. The crew temporarily re-switches the radial pattern network, transfers the interrupted customers onto another feeder, and then repairs the damaged feeder.

Loop systems, although very rare in North America, are standard practice in Europe and Asia. Basically, loop systems consist of two paths between the power sources and every customer. The complexity of a loop system is only slightly greater than a radial system. The loop system is characterized by power flow out from both sides toward the middle, with only one of two possible routes. If voltage drop, equipment sizing, and protection engineering is done properly, the loop system is more reliable than a radial system.

The most complex, most reliable, and hence most costly distribution system is the meshed-network. Meshed networks are almost always found upstream in transmission systems, but are extremely limited in their use of distribution systems. Meshed-networks can be the most economical method of power distribution when applied in densely populated urban areas, where overhead networks are space constrained and a very large number of feeder and secondary circuits are needed anyway. A meshed-network contains feeders that are laid out in an interlaced manner, so that no single feeder has a single service area. The idea of a meshed-network is to mix up feeders so that each feeder partially parallels several other feeders. In the event of a feeder failure, its load is spread out over several other feeders - overloading none of them. Networks are therefore very complicated to design, build, and operate. Loading, power flow, fault currents, and protection require network techniques like the ones used by transmission planners, except they are often even more rigorous because a large distribution system can consist of 50,000 nodes – matching the size of the largest power pool load flow problem.

Distributed Generation Interaction with Distribution Systems
DG deployment onto the radially operated system can affect the grid operation. DG interacts with radial systems in three major ways, and the potential impact of each depends on both the size and the location of the unit. The three issues are power changes in flow and capacity, voltage level, and protection needs. DG can affect the performance and requirements of a feeder in these three areas.

However, it is important to recognize that the impact is not uniform at all points along the feeder, and it is not a given that the distribution ought to be radially designed and operated in a competitive energy marketplace. Quite possibly, radial systems may not render the flexibility and interaction needed to bear out the ancillary benefits of DG such as voltage support, or reserve margin. However, this limitation is not fundamental or axiomatic. The distribution wires and transformers do not mind carrying electricity in either direction. The unidirectional bias stems from the way the protective relays and voltage regulators, for the most part, are set up by existing convention. Those devices, too, can be configured to accept bi-directional flows. In fact, there is no technical reason why the passive, radially organized distribution tree-structure could not evolve into an automated, intelligent, active, omnidirectional network or web. The barriers to such a shift are reluctance to change from a conventional system that we know works, and economics. Bear in mind that the grid could still be physically laid out in radial form, but operated as a meshed network.

Clearly, whatever form the grid takes, an increased penetration of DG could affect overall grid security. The bulk power system has been traditionally designed for preventative, rather than real-time control. A basic design and operation criterion for the power system as a whole, is the (n – 1) criterion, which denotes system reliability must be unaffected by the failure or removal of any single system element. The (n –1) criterion defines the reserves required by the system, which is made larger as the capacity of the largest downstream element increases, but which decreases as systems become more meshed. This is why transmission systems are meshed networks – power can flow from other sources in case of an emergency. DG can affect this reliability contingency in a positive way. If extensively deployed, DG resources can be made available to temporarily serve affected load, thereby relieving the transmission grid of this responsibility. This may push down the level of future centralized base load stations and reduce the capacity of the largest generating facility, which ultimately could result in lower reserve margin requirements. However, practical application of DG at this level of evolution will require a different network topology, significant automation at the substation level of the grid, intelligent electronic devices at the DG site that are connected to the substation and/or the system controller. Communication will need to be bi-directional and allow for control, monitoring, and reporting of the DG units.

The basic interconnection equipment requirements for DG consist of several general types of devices. Depending on the application, size of DG unit, and location in the grid, more or less equipment may be needed, with varying amounts of design engineering and field labor to install and commission the interconnection. However, for illustrative purposes, the equipment is classified as:

1) Power Transformer for the generation source
2) Metering
3) Voltage and Current Transformers for protective relays and meters
4) Visible Gap Safety Disconnect Switch, possibly load-break type
5) Communications with Remote Monitoring and/or Dispatch
6) Generator Circuit Breaker
7) Synchronism Check Protective Relay (25)
8) Over/Under Voltage Protective Relay (27/59)
9) Over Current type Instantaneous, Inverse Time Protective Relay(s) (50/51, 50/51N); possibly voltage – restrained (50/51V-R)
10) Over/Under Frequency Protective Relay (81O/U)
11) Additional Protective Relays can be required on larger (2500kW+ units, which include: DirectionalOvercurrent Relay (67)), Phase Imbalance Relays (46,47), Impedance Relay(s) with Timer (21), Transfer Trip Transmitter/Receiver, and more.
12) Approval Test/Inspection from appropriate third party or listing agency
13) Conformance to design and operation standards American National Standards Institute (ANSI), Institute of Electrical & Electronics Engineers, (IEEE), National Fire Protection Association (NFPA), National Electrical Code (NEC), International Electrotechnical Commission (IEC).

In short, there are three primary concerns on interconnection from the utility perspective. First, the safety of the line personnel must be maintained at all times. CHP and other DG systems must provide assurance that in the event the utility takes a line out of service for any reason, the DG system must not inadvertently energize this circuit. Second, the safety of the utility equipment must not be compromised in any way. This directly implies that a DG system failure must not result in damage of the utility system to which it is connected. Similarly, a fault on the utility distribution system must not have the ability to damage the DG system. Third, the reliability of the distribution system must not be compromised in any way. The much discussed issue of what happens to the grid under increasing degrees of DG deployed throughout the grid is not a trivial matter, nor is it easy to demonstrate dynamically. Since distribution system components are sized and adjusted for the expected configuration of generation on one end only, added generation components from somewhere else present potential system instabilities. In other words, the grid, by design, can be exposed to different fault currents, energy flows, and grounds created by the introduction of other generation sources.

Regulatory and Legislative Policy Issues

At present, utility interconnection requirements for CHP and other distributed generation equipment can be characterized as non-standardized, outdated, and often overly stringent. The lack of standards pose technical, economic, and legal barriers to entry for small-scale grid connected generation. As a result, uncertainty and arbitrariness associated with these requirements have dampened CHP market growth.

First, they increase project costs across the value chain – the end-user, the equipment vendor, the installer, the owner, and the operator (i.e. end-user, independent energy services company, utility, etc). Second, they make it very difficult for equipment manufacturers to produce a modular package. Whether the on-site technology is a micro-turbine, fuel cell, small gas turbine, or diesel engine-generator set, the lack of interconnection standards hampers the efforts of CHP or other local generation equipment manufacturers to realize economies of scale. Thus, the lack of uniformity from state to state, as well as from utility to utility within a given state, discourages the economic business case for on-site generation, no matter the market segment or type of end-use application.

Typical utility interconnection requirements tend to treat small-scale customer owned generation the same way they treat large-scale PURPA facilities. These utility guidelines often define customer-owned generation by size of generation (MVA), and location in the grid (e.g. Voltage level). The guidelines tend to be classified as 'non-utility owned', or 'customer-owned', or 'on-site dispersed generation'; and are usually subdivided into three, four, or five increasingly complex interconnection agreements depending on the unique character of the specific utility grid. In general, guidelines were formally documented as a result of requirements stemming from PURPA, in 1978. Further revisions and additions to these guidelines were the result of both an increasing numbers of merchant independent power producers, and smaller on-site, customer-owned generation.

Regulatory and legislative interconnection policy initiatives, although not yet mainstream, are gaining momentum due to efforts in a few states. The regulatory treatments thus far have addressed policy matters as they pertain to safety, reliability, utility interests in contractual and operational integrity, customer requirements for ease of local generation acquisition and installation, and equipment sellers' need for uniform national standards.

Regulatory commissioners and their staff tend to be saddled with a heavy workload that spans several regulated industries. Additionally, many do not have technical backgrounds or in-depth power industry expertise. Legislators and their staff possess an even broader agenda in comparison to regulators, so they are even more constrained in their ability to learn about how the power industry works, and what local generation or interconnection legislative policy is required. As a result, local generation in general, and interconnection in particular, has thus far suffered a regulatory and legislative policy gap. The policy gap is in part due to a lack of consistent, concise, objective, and intellectually sound message from the stakeholders. Trade groups such as the Distributed Power Coalition of America

(DPCA) and the U.S. Combined Heat and Power Association (U.S.CHPA) provide a more unified industry message of both education and advocacy to policymakers.

Market Barrier Impact

The degree to which various utility-specific interconnection requirements have been revised and expanded has often been directly related to the local marketplace activity in on-site generation. Utility sponsored interruptible rate programs that incentivize peak shaving, load curtailment, and peak capacity solutions have developed alongside end-user focused peak shaving projects. Both applications have generally been based on traditional gas or diesel engine-generator sets, where the all-in embedded cost to interconnect has not often been substantial enough alone to affect a given project's feasibility. Such projects tend to range from 500kW to 5MW, and depended on important feasibility factors such as the customer load profile, utility rate structure, capital equipment cost, variable operation & maintenance cost, utility incentives, financing options, and standby power value.

The cost elements required to comply with existing utility interconnection requirements consist of a custom engineering effort and a lengthy negotiation process between the utility, the equipment providers, and project consulting engineers (often utilized due to the customized nature of each project). In order to gain interconnection compliance, each project developer must submit, review, and often modify system interconnection designs, one-line diagrams, device-level equipment specifications, and wiring diagrams. In other words, the conceptual design for the intended application, as well the actual interconnection device specification must be approved before such equipment is procured and installed. After the design and devices are approved, then site inspections are required, which are coordinated with the project developer, owner, and the utility. Whether or not the all-in costs incurred by this process are passed onto the customer or carried by the utility, they often represent an unnecessary and substantial burden on both utility personnel and the customer.

B. California Interconnection Issues and Policies

Current Situation

Before deregulation of the power industry in California, developers, manufacturers and users were forced to deal with utilities on the utilities' terms. With deregulation, a greater interest in developing on-site and localized generation has emerged. As entities began looking into DG projects, they quickly realized that many of the rules written during the time of a power monopoly needed to be re-examined, including rules governing interconnection.

Historically larger generation projects (tens of megawatts and larger, whether cogeneration or regular power plants) relied on engineering ("EPC") firms to provide engineering, procurement and construction services. Typically the engineers would meet with the utility's engineers to work out any interconnection requirements. Eventually utilities began to organize these requirements into formal documents. Also, projects of this size, 10 MW +, could afford more comprehensive and complex protection equipment. Spending $100,000 for disconnects, breakers, relays and associated equipment was not unusual. Now, with smaller CHP (less than 1 MW), being contemplated, such costs are prohibitive.

The ongoing debate in California over interconnection issues can be viewed as a tug of war between two opposing parties. The utilities are holding to their traditional role as monopoly providers of reliable service to all customers. Opposing are the manufacturers, developers and users of generation equipment (and associated products and services) wanting to connect their equipment to the utility system. Each has its own viewpoint and interests. Each has difficulty relating to the other side's issues.

Deregulation in California has created opportunities for developers of DG (including CHP) in the state to capture efficiency and reliability inherent in on-site self-generation, including heat capture, rate unbundling and load management that are not possible in the current context of utility-delivered separate heat and power. The recent Order Instituting Rulemaking for Distributed Generation and Distributed Competition heard a similar message from a wide variety of discussants: non-standard interconnection requirements will be the primary obstacle to delivery of the full benefits of deregulation.

The utility engineers, being conservative in nature, rely on proven engineering design and operating practices to ensure the integrity and reliability of the grid. Their approach is based on years of experience obtained from building central station power plants, distribution lines and transmission lines. Complicating this even further, the general issues may be the same (safety, protection, etc.) but engineers have different ways of addressing these issues. Their approach will depend on traditional practices at their utility and their personal experiences.

Adding to this built-in inertia to change are possible management policies that hinder assisting potential competitors. Why should a monopoly utility assist a competitor in taking customers away? Most utilities see DG as a natural service for them to provide.

In the other camp are developers and manufacturers focused on developing their particular product. In some cases, this product has been designed as a separate entity without regard to its interaction with a larger system. Also when faced with the differing interconnection requirements across utilities and regions, they can't understand why there are differences. In addition, the need, cost and time required for utility studies (to determine the impact of the generation on the utility system) seems obstructive to them.

A collaborative effort in California, called the PV Alliance, created a "Model Net Metering Interconnection Agreement" (see Appendix 6) which helped to standardize interconnection for photovoltaic systems less than or equal to 10kW. This effort can be used as a miniature model for future interconnection efforts that encompass a much wider range of technologies and sizes.

The California Alliance for Distributed Energy Resources (CADER)

CADER has represented the leading-edge policy towards Distributed Resources (DR) overall, and in keeping with that vision, CADER adopted a committee dedicated to interconnection policy. The committee has been very active, and holds regular conference calls, email discussions, and collaborative meetings as a group. The committee is called 'Interconnect and Safety Standards, Dispatch, and Communication Protocols Committee', or INCOM. INCOM is an ad-hoc group with dozens of members from across the industry, and its Honorary Chair is Edan Prabhu. INCOM's Mission Statement reads "Facilitate the timely adoption of policies and standards to allow safe, reliable, cost-effective interconnection of Distributed Resources to the California grid. In this context, 'interconnection' includes related communication and control needs."

INCOM is organized into four workgroups: Technical & Safety, Regulatory & Legislative, Macro-impacts, and State & Federal Coordination. INCOM's role includes education and consensus-building by collaboration with key policy makers and stakeholders, at the national level, as well as in California. INCOM seeks to promote and participate in important interconnection policy efforts, as an active supporter. The group will monitor such efforts, provide recommendations, and generally serve as liaison to allied ad-hoc and formal organizations.

INCOM has held consensus building meetings of its members. These meetings focused on the technical issues ,. A result of these meetings has been a review document covering the interconnection requirements of SCE, SDG&E, PG&E and SMUD. (This document is shown on the last page of Section F of this paper.) The Technical Director of INCOM, Mike Edds, is also a member of the IEEE working group developing national standards. Through this liaison with the IEEE (and other technical groups) information is exchanged to keep abreast of the latest developments and to ensure consistency in the results of all groups involved.

Resolving the Issues in California

In order to address this problem, the Interconnection Committee (INCOM) of CADER began meeting with the various stakeholders to bridge this gap. INCOM has taken the published interconnection requirements of the major California utilities and condensed them into a review document. From this review document and subsequent meetings, INCOM has been working to obtain a consensus on interconnection requirements.

Of particular interest is the way the requirements are presented: as specific solutions to potential problems. An example is the traditional reliance by utilities on separate discrete relays for system protection (against overcurrents, phase imbalances, off-frequency, etc.) Some utilities have gone as far as stating the requirement that specific relays, by certain manufacturers, must be used. As many of the new forms of generation use static power converters, with integrated protection and control, this requirement for separate discrete relays appears to be excessive and unnecessary to the manufacturers.

INCOM is currently working on converting the solutions-based requirements into performance-based requirements. This would allow a manufacturer to select the solution that best fits his design and still be accepted by all utilities.

C. Overview of Existing Interconnection Requirements

This overview is based on work performed by INCOM in pursuing a consensus among stakeholders concerning interconnection requirements. Published documents from Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Pacific Gas & Electric (PG&E) and Sacramento Municipal Utility District (SMUD) and the Los Angeles Department of Water and Power (LADWP) were reviewed.

Summary of General Requirements

Table 1 lists, in a matrix form, a summary of the general requirements of these utilities. (Specific requirements on protection will be discussed later.) These requirements have been separated in three categories for convenience: Pre-Installation & Operation, General Design and General Operation.

Table 1: Summary of General Requirements (as of June 1999)

		SCE	SDG&E	PG&E	LADWP	SMUD
A.	Pre-Installation & Operation					
1.	Interconnection Studies Required?	Yes	Yes	Yes	?	Yes
2.	Review and Approval of Design?	Yes	Yes	Yes	Yes	Yes
3.	Right to Inspect Facilities: Pre & Post Connection?	Yes	Yes	Yes	Yes	Yes
4.	Signed Contract(s)/Agreement(s) before Connection?	Yes	?	Yes	Yes	Yes
5.	Must meet all applicable codes and requirements of other authorities?	Yes	Yes	Yes	Yes	Yes
6.	Provide Maintenance and Calibration/Test Reports and/or Witness Tests?	Yes	Yes	Yes	Yes	Yes
7.	Provide Proof of Insurance	Yes	?	?	?	?
8.	Conduct Pre-Parallel Tests	?	?	Yes	Yes	Yes
B.	General Design					
1.	Disconnect Required? (M = manual; LB= Load break)	Yes M	Yes M, LB	Yes M	Yes	Yes M
2.	Protection Requirements Vary According to Capacity and/or Voltage?	Yes	Yes	Yes	Yes	Yes
C.	General Operating					
1.	Reactive Power and Voltage Control	Yes	Yes	Yes	Yes	Yes
2.	Must meet Power Quality standards?	Yes	Yes	Yes	Yes	Yes
	Note: “?” means not specifically discussed in documents.					

Most of the requirements are self-explanatory. More thorough explanations can be found in the original documents listed in the Reference section at the end of this paper.

Referring to the table, most of the requirements listed are mandatory. Where the requirement is not specifically addressed in the documents (as noted by the “?”) it may be an undocumented requirement. Generally the utility will execute an interconnection agreement with the power producer spelling out terms and conditions for interconnection. If power is to be sold to the utility, then a power purchase agreement will also be executed. These agreements will spell out exactly what is expected of each party.

One result of the INCOM process is that the utilities involved are more aware of each other’s requirements and will most likely up-date their own. An example is that SCE, for generation less than 10kW, will allow the meter to function as the disconnect device.

SCE was unaware the other utilities were more stringent in requiring a separate disconnect device. SCE could decide to require a separate disconnect device in the future. SCE is also updating their requirements to take into account possible ISO metering requirements. The LADWP is also reviewing its requirements, partially as a result of its recent support of small-scale renewable generation, mainly photovoltaics.

Summary of Protection Requirements

Protection of the utility system is the utmost concern of the utility. Some of the documents were very detailed in the type and application of required protective devices. Each utility also requires different protection functions according to the capacity (rated kW) of the generation and to the voltage level at the point of connection. There is also some discussion of protection based on the type of generation (induction, synchronous and inverter.) Protection requirements are also broken out according to line or generator protection. Line protection refers to protecting the associated utility power line, distribution or transmission. Generator protection refers to the generator only.

It should be noted that each utility has stated that these published requirements are minimal. The utility may impose additional requirements, depending on its review of the project. Also, the purpose of the protection requirements is to protect the utility system, not the generation facility. The facility’s owner is solely responsible for providing adequate protection for generation equipment.

The particular protection functions required for a generation project vary with capacity. In most cases smaller capacity generators (10kW and less) require minimal protection devices: a disconnect device, a generator circuit breaker, over-voltage protection, and over- and under-frequency protection. As the capacity increases more protection is required. As an example, Table 2 shows the protection requirements for generators operating in parallel with PG&E.

Table _2, Control, Protection and Safety General Requirements (PG&E)
By Generator Size (Note 1)

Device or Feature	10kW or less	11kw to 40kW	41kW to 100kW	101kW to 400kW	401kW to 1,000kW	Over 1,000kW
Dedicated Transformer (Note 2)	-	X	X	X	X	X
Interconnection Disconnect Device	X	X	X	X	X	X
Gen CB	X	X	X	X	X	X
Over-voltage Protection	X	X	X	X	X	X
Under-voltage Protection	-	X	X	X	X	X
Under/Over-frequency Prot.	X	X	X	X	X	X
Ground Fault Protection	-	-	X	X	X	X
Over-current Relay w/Voltage Restraint	-	-	-	-	X	X
Synchronizing (Note 3)	Manual	Manual	Manual	Manual	Manual	Automatic
PF or Voltage Regulation Equip.	-	-	X	X	X	X
Fault Interrupting Device (Note 4)				X	X	X

Notes:
1. Detailed requirements are specified in PG&E's current operating, metering and equipment protection publications, as revised from time to time by PG&E and available to the Producer upon request. For a particular generator application, PG&E will furnish its specific control, protection and safety requirements to the Producer after the exact location of the generator has been agreed upon and the interconnection voltage level has been established.
2. This is a transformer interconnected with no other Producers and serving no other Utility customers. Although the dedicated transformer is not a requirement for generators rated 10kW or less, PG&E recommends its installation.
3. This is a requirement for synchronous and other types of generators with stand-alone capability. For all such generators, PG&E will also require the installation of "reclose blocking" feature on its system to block certain operations of PG&E's automatic line restoration equipment.
4. To be installed by the Producer at the point where his ownership changes with PG&E.

SMUD's requirements closely follow PG&E's for generator protection. PG&E has the most comprehensive and detailed description of metering, protection and control requirements of the utilities reviewed. For example Section G2, of the PG&E handbook, on "Protection and Control Requirements for Generation Entities" has nineteen subsections.

One of these subsections is protection. Table 3 shows the requirements for line protection as a function of interconnection voltage on the PG&E system. As a general rule, higher voltages require more complex protection. This is because higher voltage lines generally carry more power and are more critical to system integrity and reliability. SMUD has similar line protection requirements (for line voltages of 69-kV and above), with the addition of current differential relaying for some circuits.

Table 3: Line Protection Devices (*minimal*), from PG&E

Line Protection Device	Device No.	34.5kV or less	44kV, 60kV or 70kV	115kV	230kV
Phase Overcurrent (OC) (radial systems)	50/51	X	X		
Ground OC (radial systems)	50/51N	X	X		
Phase Directional OC	67		X (note1)	X	
Ground Directional OC or Transformer Neutral	67N 50/51N		X (note1)	X	X
Distance Relay Zone 1	21Z1		X (note1)	X (note1)	X
Distance Relay Zone 2	21Z2		X (note1)	X (note1)	X
Distance Relay Carrier	21Z2C			X (note1)	X
Ground Directional OC Carrier	67NC			X (note1)	X
Distance Relay Carrier Block	21Z3C			X (note1)	X
Pilot Wire	87L			X (note1)	X
Permissive Overreaching Transfer Trip (POTT) or Hybrid	21/67T			X (note1)	X
Direct Transfer Trip	TT	X(note2)	X(note2)	X(note2)	X(note2)

Notes:
1. May be required on transmission or distribution interconnections depending on local circuit configurations, as determined by PG&E.
2. Transfer trip may be required on transmission-level or distribution-level interconnections depending on PG&E circuit configuration and loading, as determined by PG&E. …(*see document for complete note.)*

In contrast to the requirements set forth by PG&E, Table 4 shows SDG&E's minimal requirements.

Table 4: Minimal SDG&E Protective Devices, by function

Generation < 100 kW	100kW to 1MW	Greater than 1MW
(Notes 1,2,3)		
51 (all phases)	51 (all phases)	51 (all phases)
27 (all phases)	27 (all phases)	51N/51G
81U	81 O/U	27/59
25 or equivalent	25	81 O/U
	46	25
		46
		Telemetering or Sup. Equip.

Notes:
1. For voltages less than or equal to 480, need dedicated transformer, except for generators less than 10kW or induction generators less than 100kW.
2. For induction generators less than 10kW, the protective devices are recommended, not required.
3. 51 = phase overcurrent; 51N or G = residual or ground overcurrent; 27 = under voltage; 59 = over voltage; 81 O/U = over/under frequency; 25 = synchronizing; 46 = phase current imbalance.

Comparing the PG&E and SDG&E tables above, SDG&E's requirements look easier and less expensive to meet than PG&E's, since they are less involved. This may not be the case. The published requirements are minimal and subject to change once the utility has reviewed the proposed design. The project developer will not really know what is required until the utility has reviewed the design.

SCE presents their typical protection requirements (Table 5) in a different manner: by generator type, rating and ownership of protection.

Table 5: Typical Protection Requirements for SCE, by Device Function

Synchronous Parallel Generation Edison owned Protection (>200 kVA)	Induction Parallel Generation Edison owned Protection (>200 kVA)	Synchronous Parallel Generation Producer owned Protection (>200 kVA)	Induction Parallel Generation Producer owned Protection (>200 kVA)	Parallel Generation Under 200 kVA
(Note 1)	(Note 1)	(Note 2 & 3)	(Note 2 & 3)	(Note 4)
(Re Fig. 5.1 in Handbook)	(Re Fig. 5.2)	(Re Fig. 5.3)	(Re Fig. 5.4)	(Re Fig. 5.5)
		Required,Line:	Required,Line:	Required:
SCE 52	SCE 52	Prod. 52	Prod. 52	Prod. Gen 52
Prod. 52 or DS	Prod. 52 or DS	25 (2: Line & Gen)	25 (Line)	47
25	25	51N	51N	27/59
51V or 67V	51, 51V or 67V	47	47 (2: Line & Gen)	81O/U
51N or 59G	51N or 59G	67V	81O/U	
27/59	27/59	81O/U	27/59	
81-O/U	81-O/U	27/59		
47/79	47/27	Suggested:	Suggested:	
78	32 (re Fig. 5.2)	51 (Line)	51 (Line)	
32 (re Fig. 5.1)		32 (Line)	32 (Line)	
		78 (Line)	51N (Line)	
		47 (Gen)	87 (Gen)	
		87 (Gen)	27/59 (Gen)	
		27/59 (Gen)	40	
		40	46 (Gen)	
		46 (Gen)	51V (Gen)	
		51V (Gen)		

Notes:

1. For interconnection voltages greater than 34.5 kV, Edison will install, own and maintain, at the Producer's expense a parallel generation interconnection at the Edison point of interconnection. For interconnection voltages at 34.5 kV or lower, either the Producer or Edison, at the Producer's request, can install, own and maintain the interconnection facilities.

2. Limited to interconnection voltages of 34.5 kV and lower.

3. In specific installations, particularly with large generators (over 10,000 kVA), SCE may require specific additional protection functions.

4. Producer may be required to be served through a dedicated distribution transformer that serves no other customers. Also, inverter systems shall meet the requirements of IEEE Standard 519-1992, "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems."

Clearly there needs to be a re-examination of all utility requirements to make them more consistent and to simplify them where possible. As the current requirements were written during a time when utility engineers had exposure only to larger generation projects, the current requirements are likely to be too burdensome on smaller projects.

D. Technical, Economic and Policy Barriers

What follows is a list of barriers with discussion of each, followed by a generic case study of highlighting some of the usual barriers encountered when interconnecting DG. Other barriers may exist and will certainly be identified as actual DG projects proceed.

Barriers

No Incentive for Utilities to Re-Write Interconnection Requirements

Utilities have no business reason to rewrite their interconnection requirements to be more acceptable to local generators. Continuing the status quo limits utility competition and reduces the cost and risk associated with change. Most of the requirements were developed by the utilities based on practices outlined largely during the PURPA QF rulemaking twenty years ago

Distribution System Design Limitations

The distribution system is not currently designed to operate with DG backfeeding significant amounts of power into the grid. The distribution system was designed for one-way power flow, not two-way. In general, the hardware advances made in microprocessor-based protective devices and software innovations for system protection and control are not addressed in the current published interconnection requirements. This tends to favor, whether by design or not, older versus newer technical solutions. In fact, it could be argued that the distribution grid interconnection design and requirements is approximately analogous to what happens when a 10 –15 year old personal computer is loaded up with the most recent graphical operating system software. Technology innovation must be brought up to snuff with regard to how utilities evaluate and determine CHP and general DR interconnection standards, while not compromising either safety or reliability.

Non-Uniformity and Uncertainty of Requirements

There are differences in interconnection requirements among the utilities requiring different relay packages. One utility may require a phase voltage imbalance relay, where another requires a phase current imbalance relay. Each utility has different capacity break points for deciding what protection is required. Implementing some of the interconnection requirements may be more complex than necessary. The published requirements are minimal, so actual requirements are not known until the utility completes its studies and project review. For example, some utilities might require draw-out construction and visible trip targets for their protective devices while others might not. There are direct material cost differences due to these and many other inconsistent requirements.

Cost to Implement

This is the major issue. Because of the non-uniformity and uncertainty of the existing interconnection requirements, it is costly to implement them on an individual basis.

The costs can include direct material, application engineering, project developer and utility engineering review, testing and field labor. These costs reflect on the bottom line project cost, and the opportunity cost of often significant time commitments to struggle through such a process. The window of opportunity for a project can be lost if a project depends on being on-line for summer peaking capacity season, or any other seasonal application. All of these issues create a discriminatory bias against CHP and distributed generation.

Projects to install larger units, those over 1MW in size, are less impacted by the economic burden of interconnection. A unified set of requirements will lower costs for these projects, but interconnection is less often a deal-breaker than it is for smaller projects. Large projects have larger budgets and can more easily afford additional electrical equipment. Projects installing units smaller than 1MW are more likely to be stymied by high costs of interconnection, because interconnection is a larger proportion of overall project cost.

For example, smaller units, like the microturbines, are being designed to have all the protection functions built into the control/electronics package that goes along with the turbine itself. Microturbine manufacturers would like to claim that these units are "plug and play": all one needs to do is plug it in and turn it on. This will not be the case in the near future. First of all, it will take another year or two to arrive at revised interconnection requirements. These revised requirements may be less restrictive for smaller capacity generation, but most likely will require certification of the control/electronics package by an independent testing lab. Before equipment can be certified it has to be tested to some standard accepted by the utilities and manufacturers.

For the next year or two, then, the manufacturers will have to comply with the current interconnection requirements, or a slightly modified version. For the example given, this will mean adding a redundant protection package to each unit, separate from the built-in functions. Depending on the of device and manufacturer, the equipment costs can be in the thousands of dollars. Engineering and installation costs will add to this.

Here is an example of the added cost of today's non-standard interconnection requirements. A 30-kW microturbine unit is available today for about $33,000[3] uninstalled (for locations with high pressure gas; low-pressure gas systems are more expensive), or $1100/kW. Although this unit is likely to have its own set of protection, the utility will require an additional redundant protection that will cost an estimated $8,000 additional; $4,000 for a back-up protection relay package and $4000 for interconnection engineering and installation (not including installation of the microturbine itself). Now total cost of the 30kW unit is about $41,000 uninstalled. This is almost a 20% increase in cost that could be eliminated with a set of standard interconnection requirements.

[3] Capstone Turbine Corporation, *Model 330 Pricing and Availability*, 1999

Another significant hurdle is the cost and time required for the utility to perform its review and system studies. This can add thousands of dollars and weeks or months to the schedule. The utilities generally have not explained how they arrived at these costs or time requirements. Sometimes these costs can be reduced by working directly with the utility engineers on specific system impact issues or through negotiation.

Acceptance of Static Power Conversion Equipment

Utilities lack familiarity with modern static power converters that have software-based protection functions. Protection engineers are reluctant to accept manufacturer's assurances that their equipment performs as advertised. This attitude is a result of being disappointed in the performance of relays from historically accepted suppliers. Protection engineers need to be convinced, beyond any doubt, that such systems work reliably as designed.

Static Power Converters are Inadequately Addressed in the Interconnection Requirements

The current interconnection requirements are not suitable for static power converters (SPCs.) The existing requirements were written to address primarily rotating equipment, so they do not address the unique characteristics of modern SPCs (software-based relay functions and fast reaction time.)

Utility Studies

Some stakeholders have questioned the necessity of comprehensive utility studies. They tend to be expensive (a cost borne by the customer) and take too much time. Such studies also tend to be on a "need to" basis, without explicit rationale or rules to follow. This ultimately results in unexpected cost and time barriers.

Tariffs

Customer-sited generation requires in most cases a back-up source of power to meet load requirements during generation outages or routine maintenance periods. Utilities now charge not only for the power used, but also for the reserved generation and distribution capacity. High stand-by charges reduce the economic benefits of DG. Standby charges by SCE, PG&E and SDG&E contain transmission, distribution and generation components. The charges vary by voltage level and within each the components also vary. An example would be standby charges for service at the secondary voltage level for customers in the 20-kW to 500-kW load range. This is usually below 2-kV. The following table breaks out the standby charges at this level:

Standby Charges of CA IOU's at Secondary Voltage Level: by components, in $ per kW-month

Utility System	Transmission	Distribution	Generation	Total
SCE	0.13	3.61	2.66	6.40
SDG&E	0.38	1.50	1.87	3.75
PG&E*	0.99	1.56	0	2.55

Note: * PG&E applies this charge to 85% of the contracted reservation capacity.
Also, PG&E has a non-zero generation charge at other service voltages.

For a 500-kW standby demand, the monthly charges would be $3,200 for SCE; $1,875 for SDG&E; and $1084 for PG&E.

Entitlement for Non-QF's:

As mentioned above, the effects of PURPA linger in utility conditions for interconnection. Regulated utilities in California abide by the provisions of PURPA. Their current interconnection requirements address only QF's, not non-QF's. Municipals don't appear to differentiate between the two when it comes to the interconnection requirements. The regulated utilities (SCE, SDG&E and PG&E) in California will allow non-QF's to interconnect but will not buy their power. SMUD and LADWP, at least in the reviewed documents, do not differentiate between the two, allowing either to connect. A non-QF that wants to sell power may have to apply for exempt wholesale generator (EWG) status, and sell its power through the California Power Exchange or some other power market. The EWG may also have to adhere to California Independent System Operator (CAISO) rules if it has to transmit its power over the state transmission system.

Metering, Control, & Communication Issues

Up-to-date requirements are often not clearly outlined for metering, control, and communication of interconnected CHP or DR. Again, barriers associated with a lack of information and rules to live by exist. This area, in particular, is one that is most impacted by technology innovation. Embedded software (firmware) based products with programmed intelligence and inherently lower functional costs due to the power of the micro-processor are beginning to change forever the structure and operation of the transmission and substation portion of the grid, as well as the actual on-site generation equipment. Interconnection should not be left out of the technology advancements because of outdated requirements and those requirements should not stand in the way of system improvement.

Generic Case Study

A generic generation project will be presented in order to illustrate the design issues that have to be considered. This project will address adding a small cogenerator inside an existing facility.

Assume a facility is connected to a 15-kV class utility distribution line through a 500-kVA 3-phase main transformer owned by the utility. The winding configuration is delta high side and wye low side (480-v) with grounded neutral. The high side is fused at the line tap. The transformer secondary feeder connects to a main incoming panel through a low-voltage molded case breaker (main breaker) with an adjustable trip element. From this panel, subfeeder circuits originate through individual breakers. These subfeeders connect to branch panels to serve load circuits at 480 volts or to step-down transformers that feed 120/208 v branch panels. Metering takes place before the incoming main panel at 480-v.

The facility's owner decides to add a small cogenerator (rated at 480-v, three phase, 150-kW) to serve part of the facility's load with "no sale" to the utility. His peak load is 350-kW, with a minimal load of 175-kW. How does the facility's existing electrical system have to be modified to accept the cogenerator?

The following discourse will present, in a cursory fashion, design issues that have to be considered and what equipment will have to be added. This effort should be carried out before submitting any plans to the utility. After these issues are resolved at the customer level, a preliminary design can be submitted to the utility for their review and approval. This design will be subject to change depending on the results of the utility's review. It goes without saying that the National Electrical Code has to be followed in specifying conductor sizes, breakers, and other associated equipment. These normal design issues will not be covered here.

1. *"No-Sale"*

   The "no sale" restriction means all generation will be consumed in the facility with no back feeding of power to the utility. A reverse power relay (device 32) will have to be added to insure no power flows back to the grid. One location for this relay could be the secondary of the main transformer, most likely at the main incoming panel. If the relay is located here, and the relay ever operates, the entire facility will lose power. Another location could be a point just upstream of the generator interconnection point. Care has to be taken in selecting the location of this relay to make sure any loads that are lost, as a result of this relay operating, will not compromise electrical service to the rest of the facility. Regardless of location, current transformers and potential transformers will have to be added to each phase of the three-phase 480-v circuit in order to feed current and voltage signals to the relay.

   Just for this one relay, there are the equipment costs (relay, three CT's, three VT's, wiring), engineering design costs, installation cost, and lost production costs for shutting down the facility to install the equipment. The total cost could reach a few thousand dollars.

2. *Connection Point and Circuit Changes*

   As the generation will be at 480-v, possible connection points inside the facility have to be looked at. Does the main incoming panel have spare breaker space? Can the panel handle this additional power? Should a new panel be required? What type of breaker should be used with this generator? What type of disconnect switch should be used and where should it be located? Can the generator be located on a branch 480-v circuit? Are there any spare breaker spaces at this panel? Can this panel handle the additional power? Would new breakers, with adjustable trips, be required? If the utility goes down should certain loads be isolated with the generator to continue operation? If so, how will reconnection occur? Do connection points of loads have to be moved?

These issues require much engineering analysis and possible design effort. It is not a trivial matter adding generation to an existing electrical system. Not only does the designer have to consider the impact the generation will have on the utility, but also what impact it may have on the facility's system. The cost of this effort can easily be in the thousands of dollars.

Many manufacturers of small generators, such as microturbines and fuel cells, expect to eliminate the need for this analysis and design effort. This may be true for very small generators (< 10-kW). Someone will still have to do at least a cursory analysis of the proposed installation to make sure the facilities existing electrical system is not compromised and meets local codes. Design certification may even be a requirement for acquiring insurance. As the units get larger, more comprehensive analysis and design will be required, as they will have a greater impact on the facility and the grid.

3. *Type of Generation and Protection*
What type of generation is being considered? Synchronous machine? Induction machine? Generation that uses a static power converter (SPC)? The type of generator will make a difference in protection requirements. A synchronous machine will require synchronizing relays (device 25). Induction generators generally require minimal protection: over and under frequency (81O/U), and over and under voltage (27/59). (Sometimes the utility will allow a contactor to act as the undervoltage device.) SPC's, even though they have built-in relay functions, under the current requirements would require back-up protection. This could be one or two solid-state multifunctional relays or separate multiple discrete relays.

Needless to say, the protection relays can be a major cost item especially if separate discrete relays are required. This is not because the individual relays are expensive but the additional engineering design effort and site installation add a lot to the cost. Sometimes it is easier to use a more expensive solid-state multifunction relay package, from utility-accepted manufacturers like Beckwith, SEL or Basler. These devices are not cheap, running into the $1000-$5000 range, but one can save just as much or more on the engineering and installation costs.

Also, a relay protection system is not simply a collection of devices. These relays have to be tested and set properly. This requires some analysis of possible fault conditions and coordination with other devices. Who is going to provide this service? The utilities expect this to be performed by a qualified testing company or engineer. Will the manufacturer or project developer provide this service? Who will bear the cost?

4. *Grounding and Line Fault Detection*
Once the type of generation has been selected and interconnection point chosen, the designer has to look at grounding and detection of faults on the distribution line. For

the system on the secondary side of the transformer, the National Electric Code has to be followed for the design of the ground system.

Regarding the utility side of the transformer, one of the main concerns utilities have is whether the generator's protection system can detect distribution line faults. The transformer winding connections has a big impact on whether these faults can be detected on the secondary side.

In this case, the transformer has a delta high-side and a grounded wye low-side. Delta windings help contain harmonic currents but do not pass through certain fault currents necessary for detection by relays. Delta windings do not have a ground connection. On the other hand, wye-wye transformer connections are generally not used because they cause other problems. For this case, a separate ground transformer may have to be used in order to create a ground connection on the high-side. From this grounding transformer, a ground detection scheme can be designed to detect some distribution line faults.

The cost of a grounding transformer and corresponding fault detection equipment can be high ($5,000 to $20,000.) One reason for this high cost is that the high-side of this transformer has to operate at the primary distribution voltage level. The transformer's primary has to be design for this higher voltage.

Finally, faults on the far end of the line may still not be detected because of their relatively low magnitude at this location on the feeder. These far-end faults may look like normal load current. This is a particularly difficult issue to resolve in distributed generation.

5. *Additional Metering*

For the cases with parallel operation with the regulated utilities, additional metering may have to be installed in order to meter the departing load. Unless granted an exemption, the competitive transition charge (CTC) still has to be collected from these departing loads. This metering would require separate CT's, VT's, associated wiring, meter sockets, etc. The cost of this metering, and telemetering of data, has to be added in to the overall cost. This could add another few thousand dollars.

E. Overcoming Barriers

Following are some preliminary recommendations for developing standardized Interconnection Requirements (IR's). These recommendations are not presented as final conclusions to be implemented, but as suggestions for where more detailed policy discussions could begin.

Recommendations for Removing Interconnection Barriers to CHP

Define Requirements Based on System Impact

Interconnection Requirements relating to protection should be based on the relative impact the distributed generation technology has on the local distribution system, at the point of common connection and further into the system.

One approach under consideration is to establish an index that would be calculated from characteristics of the generator and the distribution system. This index could be the ratio of total short-circuit current (generator + system) to generator short-circuit current. If this calculation gives a high number, 100 for example, then the DG would have little impact on the distribution system. Minimum system studies and minimum protection for the distribution system would be required.

If the number is in single digits, then the generation may have a large impact. A more thorough analysis would be required, with comprehensive system studies and a more complex protection package. There would probably be a rather high cut-off point, for example 50, where numbers less than 50 require a thorough review.

Promote Independent Certification of Equipment

An independent "third-party" equipment testing and certification center should be designated. The center should have facilities to test and certify interconnection equipment performance. The independent certifier needs to have credibility with both manufacturers and utilities; results need to attain a level of accuracy and breadth of scope that make them acceptable to all parties.

Facilitate Utility Revision of Interconnection Requirements

A mechanism must be found to persuade the utilities to rewrite their requirements to be more acceptable to local generators, whether CHP or other types. For the CPUC-regulated utilities (SCE, SDG&E and PG&E) the CPUC can require them to cooperate in this effort with other stakeholders. For non-regulated utilities (municipals, irrigation districts, co-operatives) other means must be used, such as customer demand for DG. Perhaps the only incentive for the utilities to revise their requirements is to make it less costly for them to provide DG. As many utilities see DG as a service they can provide, their own interconnection requirements can hamper their efforts to provide this service at a reasonable cost.

Evaluate Distribution System Design

The impact of DG on utility equipment performance and operations must be investigated. This would include the affect such generation has on auto-reclosers and voltage regulators; the possibility of islands developing under certain emergency conditions; the possibility of circuit breakers opening or fuses blowing unnecessarily; the ability for line protection equipment to detect far-end faults; etc. Currently this issue is being addressed by the IEEE SCC21 P1547 working group and by other technical groups (EPRI and EEI.) California stakeholders should support this work. In addition, the CEC may choose to support a study of this issue as it relates to distribution line design in California.

Develop and Promote Uniformity and Certainty of Requirements

Through the efforts of CADER and other national groups (IEEE, EPRI, EEI, etc.), a consensus should be reached on simplified uniform requirements based on sound technical reasoning. A quick and simple screening procedure should be developed to allow a developer to know up-front whether or not his project requires comprehensive review and studies. The IEEE committee hopes to develop such a procedure. As an example, the Texas PUC has already approved a clear and concise two page procedure that outlines utility review contacts, review procedures, time limits and appeal process for CHP and other DR projects.

Reduce Cost to Implement

High implementation cost is a significant barrier especially for small systems, as mentioned above. Despite the existence of some anecdotal evidence (not included here), there is a lack of data on actual interconnection costs. Once this data is collected, many believe that the cost of interconnection as a percentage of total cost will be higher for small systems than for larger systems. If this is true, then reduced costs to implement will be more a barrier for small systems than for large ones, and overcoming the barrier will require an effort directed at streamlining small system interconnection. Many of the barriers already mentioned conspire to increase system costs to install DG, particularly for systems less than 1MW in size. The strategies for overcoming those other barriers, such as system impact evaluation, independent certification, uniformity and certainty of requirements will help reduce cost to implement. Until these changes are in place, projects to interconnect small systems can be used as data to further define cost burdens and to feed into the process of regulatory change that must precede reduced interconnection costs. This solution will not necessarily increase the likelihood of small system interconnection in the next several years, however.

Promote Acceptance of Static Power Conversion Equipment

A third-party entity should be licensed to test and certify static power conversion equipment. This entity should have the support and acceptance by all stakeholders. Certification tests will also have to be developed, such as those presented in the proposed IEEE Standard P929 for anti-islanding measures.

Static Power Converters are Inadequately Addressed in the Interconnection Requirements

As the requirements are being rewritten, the characteristics of modern SPCs should be taken into account.

Simplify Utility Studies

Utility studies can not be entirely eliminated. The degree of study required should depend on the impact the generation may have on the grid, both locally and system-wide. The development and adoption of simple quick screening procedures or index would help alleviate this issue.

Review Stand-by Tariffs

The CPUC, possibly through the DR OIR, should re-examine the issue of stand-by charges and the CTC. Regulatory and contractual policy should be designed so that such tariffs, penalties, and other economic parameters are weighed with the many ancillary or system-level benefits inherent in CHP. Such benefits to the utility grid, or even to other nearby utility customers on adjacent feeders, for example, should be considered, and possibly offset stand-by or CTCs.

One could reasonably ask why the standby charge includes a generation component when the IOU's are no longer in the generation business. The customer could contract for this capacity with an ESP or from some other source of ancillary services. The same could be said for the corresponding energy charges (not shown).

Eliminate Discrimination between QF and Non-QF's

There should be no differences in interconnection requirements for QF's or non-QF's. The issue is really whether non-QF's should be allowed to connect to SCE, SDG&E and PG&E. This is a federal issue (from FERC via PURPA), and the CPUC should assist in getting this barrier removed.

Address Metering, Control, and Communication Issues

Requirements and performance-based standards should be defined, in order to encourage and recognize technology advancements, while not simultaneously favoring a particular protocol or algorithm for metering, control, or communications. At present, the practical utility use of supervisory control and communications technology is left to case-by-case solutions. System-level operation and impact, and the need for control and communication standards should be forward-thinking and reflect recent developments in this area. Many utilities are currently automating distribution substation operation. This work could be extended out to equipment on the substation feeders and could become the start of a communications and control backbone for the distribution system that DG could tie into. Guidance from leading technical organizations such as IEEE and EPRI should be sought to support this effort.

Address Controversial Issues

Investigate possible solutions to specific technical issues that have created controversy. These issues include ground fault detection methods, the need for a dedicated distribution transformer, ways to test integrated protection functions (software-based), and others as they develop. There are no easy solutions for these issues. As seen by the results of the New York effort, issues such as these can hold up any consensus on interconnection requirements.

Policy Discussions and Consensus Efforts

Recommendations for specific technical interconnection requirements, in order to carry the weight of consensus agreement and full technical review, must come out of public discussion of the issues in the forum of stakeholder meetings and workshops. This is precisely the effort currently spearheaded by INCOM through CADER. The FOCUS-Interconnection effort will be aimed at consensus on the technical requirements of a set of uniform interconnection requirements that meet the needs of customers who desire to interconnect, utilities who need to protect their system, manufacturers who wish to design and build equipment to a known standard and energy services companies and who wish to facilitate the process. The following actions and guidelines will focus and strengthen the discussion and help ensure positive results.

- Continue participation with other professional and technical organizations to work out <u>technical</u> issues. These organizations are primarily the IEEE, EEI, and EPRI. (Members include utilities, users, developers, and manufacturers),
- Work with California Public Utilities Commission (CPUC), California Energy Commission (CEC), utilities, and others to resolve *policy* issues.
- Recommend the CPUC and CEC, depending on jurisdictional bounds, offer the strength of a regulatory rulemaking on the interconnection policy matter. This would concur with the approach the Texas Public Utilities Commission has taken as a proactive policymaker.
- Persuade the utilities to abide by the results of a consensus effort.
- Remain aware of what other states are doing as a means of gaining new insight and new approaches to resolving these issues.
- Support consensus efforts such as CADER INCOM's Forging Consensus on Utility System (FOCUS)-Interconnection proposal.
- Focus the initial effort on radial distribution lines at voltages less than 25-kV. It will be easier to produce a consensus document for these systems. Later extend work into higher voltages, and then networks.

F. Developing an Interconnection Standard

The National Effort

IEEE, through its Standards Coordinating Committee 21 (SCC21), is working to produce a national interconnection standard. There is reason to believe IEEE may be successful. The interconnection standard, as with other IEEE standards, uses a voluntary consensus-based approach. IEEE has a long history of successful standards development and dissemination. IEEE is a large, well established organization with 315,000+ membership in over 150 countries. IEEE represents all forms of electro-technology through its numerous societies, divisions, and working groups. IEEE has already in place several separate working groups, guidelines, and recommended practices that pertain to DG interconnection.

The IEEE Standards Association was established in 1996 in order to provide increased responsiveness to the standards interests of IEEE society's and their representative industries. Accordingly, the IEEE SCC21 was formed in order to provide a valuable mechanism to oversee the development of standards that reach beyond the scope of the individual technical committees within IEEE's societies. The scope of the SCC21 is to "oversee the development of standards in the areas of Fuel Cells, Photovoltaics, Dispersed Generation, and Energy Storage, and coordinate efforts in these fields among the various IEEE Societies and other affected organization to insure that all standards are consistent and properly reflect the views of all applicable disciplines."

The first IEEE SCC21 meeting was held on December 9 - 11, 1998 by Chair Richard DeBlasio (National Renewable Energy Lab) in Washington, D.C. The main outcomes of the meeting were a definition of SCC21's enhanced scope of work, identification and prioritization of standards development needs, selection and initiation of project authorization requests (PARs), and identification of working groups and their chairs. Status updates on current SCC21 projects were provided. The committee stressed the need for a standard, thereby extending beyond a recommended practice, or a set of guidelines. As a result of the SCC21 initial meeting, IEEE unanimously adopted the title, scope, and purpose for a new PAR, now known as P1547. It is titled *IEEE Standard for Distributed Resources Interconnected with Electric Power Systems.* The scope of the standard is to establish criteria and requirements for interconnection of distributed resources with electric power systems. The purpose of the document is to provide a uniform standard for interconnection of distributed resources with electric power systems. It provides requirements relevant to the performance, operation, testing, safety considerations and maintenance of the interconnection.

The effort of the IEEE P1547 Working Group towards a national interconnection standard began as a process of education. Members of this group have a variety of backgrounds. There are representatives from utilities, generation equipment manufacturers, equipment vendors, trade organizations, users, government, etc. Each has his or her particular base of knowledge and mindset on this subject. Some even admit that their knowledge is limited. In light of this situation it was felt that the members had to better understand what they were dealing with, both the generation technology and the power system. Towards this end, the utility members have taken the lead in explaining power system design and operation, and the manufacturers are providing information on how their generation equipment works.

The IEEE has already done much work in both of these areas. Other technical organizations, principally EPRI and EEI, have or are currently studying distributed generation. The group decided that it should take advantage of all of this work and incorporate portions in the new standard as needed. Some of the work includes present and prior IEEE standards. These include the withdrawn IEEE Std. 1001-1988, "IEEE Guide for Interfacing Dispersed Storage and Generation Facilities with Electric Utility Systems", the present IEEE Std. 519-1992, "IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems", and the draft standard P929 "Recommended Practice for Utility Interface of Photovoltaic Systems". EPRI and EEI have indicated that they will contribute information from ongoing and past studies.

Even as this educational process continues, the group is addressing technical issues. These issues are presently focused on the impact DG has on the distribution system. Much of the information provided by EPRI and EEI specifically relates to this impact. Members have been given writing assignments to explain what the impact is for particular situations or topics. For example assignments have been given to research the following: feeder reclosing coordination considerations, voltage regulator operation, characteristics of modern electronic power conversion equipment, types of distribution systems and interconnections, characteristics of rotating power conversion equipment. This list goes on; more topics will be added as the work progresses.

Perhaps the biggest challenge in developing standards for interconnection is overcoming the mindset of each individual. Each person has a view of what distributed generation is; what it should be used for; what the standard should contain. Often the judgements held by the utility engineers or the manufacturers are based on little or no real experience with on-site generation technologies or with the distribution systems, respectively. Because of this, the educational process will proceed until sufficient knowledge and understanding is common to all members. Only then will the group produce useable results. A consensus on a national interconnection standard will then be attainable. This will not be a quick process, as it will take a few years to reach a consensus.

Additional formal gatherings of the SCC21 include bi-monthly Working Group meetings will continue for roughly the next 2 years. Upcoming Working Group meetings are tentatively set for Chicago on June 28-30, 1999 Washington D.C. on September 27-29, 1999 Tampa on November 15-17, 1999, and Albuquerque on January 24-26, 2000.

The California Effort

California has an opportunity to take a leadership role in interconnection policy. The California PV Alliance has developed an interconnection agreement for small systems (<10kW), which includes provisions for net metering. (See Appendix 6.) The legislative path taken for PV systems has information value[4]. The crafting of an interconnection agreement for PV in California gives the state greater experience to draw upon in fashioning a consensus on interconnection and interconnection policy for larger systems. California was one of the first states to deregulate generation and transmission. This process is continuing with the joint CPUC/CEC/EOB (Electricity Oversight Board) considerations on distribution. Because of this pioneering work, California will be a prime market area for DG. For this market to develop, though, California needs uniform consistent interconnection requirements. The process of developing uniform California interconnection requirements should proceed, cross-fertilizing the national efforts. The California effort can benefit from the work being done by such organizations as the IEEE, EPRI, EEI and other states.

By encouraging and supporting work started by CADER, which has tie-ins with these other organizations, a California consensus standard can be attained. INCOM, the interconnection arm of CADER (mentioned above), is leading the effort to develop a California interconnection standard through their FOCUS-Interconnection effort. CADER has already begun the consensus building among the regulated utilities, municipals and manufacturers in the state. INCOM's approach is to develop performance-based interconnection requirements where specific requirements depend on the impact the generation has on the power system. Any requirements should be transparent to the type of generation or power converter technology used. This may be difficult to do initially because of the lack of experience with these technologies (especially static power converters) and because of the existing mind-set of stakeholders. Requirements should not be based on arbitrary numbers (as they are now with capacity levels) but on sound technical reasoning, backed by experience or studies. To the best of our ability, the requirements should be written to withstand the test of time and future developments in distributed generation.

The initial stages of consensus building have included much education and discussion of experiences with the newer technology and utility systems. While this has been occurring among engineers and manufacturers, it should be expanded to include policy and decision makers in government and regulatory agencies.

The matrix on the following page is a draft work product designed to clarify key issues and to help move the group toward consensus.

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[4] IEEE will be voting in the near future on the latest draft of *Recommended Practice for Utility Interface of Photovoltaic (PV) Systems*. A copy of the document is included in Appendix 6, part two.

Draft Consensus Proposal to the ICBM, San Diego, Feb. 11, 1999				
These requirements apply only to radial distribution lines at less than 25kV.				
Requirement	**<10kW**	**10-200kW**	**200kW-1MW**	**1-20MW**
Distribution Line Ground Fault Detection?	NO	Yes	Yes	Yes
Synchronization method****	Auto or manual	Auto or Manual	Auto reqd	Auto reqd
Dedicated Transformer Reqd?	No	Yes*	Yes*	Yes**
Utility Study Reqd?	No	Yes**	Yes**	Yes
Relay Setting Reqmts (ANSI 59,51 or 51V,27, 81, 32)****	Factory settings OK	Factory settings OK	Field Setting capability reqd., coordinate settings with utility.	Field Setting capability reqd., coordinate settings with utility.
Discrete Relays Needed?****	No, they may be part of the control system with fail-safe features.	No, they may be part of the control system with fail-safe features.	No, they may be part of the control system with fail-safe features.	EM,SS, or uP with backup protection.
Periodic Relay function Testing Needed?****	No	No	Yes	Yes
Disconnect Reqd?	No	Yes	Yes	Yes
Power factor control reqd?***	Minimum 0.95 p.f. must be achieved	Minimum 0.95 p.f. must be achieved	Minimum 0.95 p.f. must be achieved	Minimum 0.95 p.f. must be achieved
Voltage control reqd?****	Voltage must follow line volts	Voltage must follow line volts	Voltage must follow line volts	Voltage must follow line volts
Metering Reqmts?****	Later	Later	Later	Later
Communication/Remote Control Reqmts?	Later	Later	Later	Later
Power Quality Std	Conform to IEEE 519-1992	Conform to IEEE 519-1992	Conform to IEEE 519-1992	Conform to IEEE 519-1992
DC Injection	DC current ≤ 0.5% of rated, per P929	DC current ≤ 0.5% of rated, per P929	DC current ≤ 0.5% of rated, per P929	DC current ≤ 0.5% of rated, per P929
* The Dedicated transformer does not have to be new. An existing transformer connected to that customer is adequate. Multiple units from one party may connect to one transformer, but each party must have its own dedicated transformer.				
** If generator output is less than transformer, simplified study. Otherwise, detailed review				
***Line power factor compensation capability reqd for capacity certification				
**** These may be solid state, electromechanical, or microprocessor-based devices, but must be UL listed. See PG&E guide, pages G2-21 and -22 for explanation of device numbers.				

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Appendix 1. Detailed Summary of CA Requirements

Review of Technical Interconnection Requirements of Utilities in California
(as of June 1999)
Includes review of PG&E, SCE, SDG&E, SMUD and LADWP.

Foreword:

The Interconnection Committee (INCOM) of the California Alliance for Distributed Energy Resources (CADER) has undertaken the task of reviewing the technical interconnection requirements of utilities/power systems in California. The primary reason for this effort is to arrive at consistent, uniform requirements for interconnection that can be applied to any and all power systems in the state. In this way CADER expects to foster the development of generation at the distribution, and consumer, level.

I. Documents Under Review:

At the time of this review, the interconnection-requirements documents of the following electric utilities were available: SCE, SDG&E, PG&E, and SMUD. As documents from other utilities become available, they will be added to this review.

Not all documents listed below were used for this review. The primary source material for technical interconnection requirements are the utility handbook/guideline, Rule 21, and any agreements available at the time. Other material is listed to make the reader aware of other important issues that have a bearing on the design on the interconnection, particularly metering.

A. Southern California Edison (SCE):
   1. Requirements for Operating, Metering, and Protective Relaying for Cogenerators and Small Power Producers; March 1994
   2. Rule 1 Definitions
   3. Rule 2 Description of Service
   4. Rule 21 Non-Edison Owned Generating Facilities Interconnection Standards
   5. Schedule S Standby
   6. Schedule DL-NBC Departing Load – Non-Bypassable Charges
   7. Preliminary Statement W: Competition Transition Charge Responsibility
   8. Small Qualifying Generating Facility Interconnection and Power Purchase Agreement (SAMPLE), for Small Qualifying Facility – 100kW or Less; Oct. 23, 1998 (Providing Host Service and Surplus Energy Sales)

9. Qualifying Generating Facility Interconnection Agreement (SAMPLE); Nov. 10, 1998 (Providing Service to Producer Owned Host Facility Only)
10. Schedule NEM Net Energy Metering
11. Net Metering and Interconnection Agreement, Nov. 20, 1998

B. San Diego Gas & Electric (SDG&E):
   1. Interconnection Guidelines for Non-utility Owned Generation (DRAFT); Nov. 11, 1997
   2. Rule 1 Definitions
   3. Rule 2 Description of Service
   4. Rule 21 Non-Utility Owned Generation
   5. Rule 23 Competition Transition Charge Responsibility
   6. Schedule PG-QF Parallel Generation – Cogeneration or Power Production
   7. Schedule S Standby Service
   8. Schedule S-I Standby Service – Interruptible

C. Pacific Gas & Electric (PG&E):
   1. PG&E Interconnection Handbook; December 15, 1997
   2. Rule 1 Definitions
   3. Rule 2 Description of Service
   4. Rule 21 Non-utility-Owned Parallel Generation
   5. Schedule S Standby
   6. Schedule E Departing Customers
   7. Preliminary Statement BB: Competition Transition Charge Responsibility for All Customers and CTC Procedure for Departing Loads

D. Sacramento Municipal Utility District (SMUD):
   1. Special Requirements – Generator Interconnection
      Electric System Design, Integrated Distribution Planning, Dec. 12, 1996
   2. SMUD's Rules and Regulations 11 and 19 (not available at the time of this review)

II. <u>CPUC Regulated Utilities</u>:

The California Public Utility Commission (CPUC) regulates the following electric utilities: SCE, SDG&E and PG&E. (Portions of other out-of-state utilities also fall under CPUC regulation. Those utilities are not included in this review.) These utilities must adhere to CPUC approved rules and regulations. Rules 1, 2 and 21 have particular bearing on interconnection.

A. Rule 1, Definitions, sets forth the definitions of expressions and terms used in the tariff schedules.

B. Rule 2, Description of Service, provides general information on:

1. Type of electric service available;
2. frequency, phase and voltage specifications;
3. allowable load specifications and limitations;
4. protective devices;
5. interference with service;
6. power factor specifications;
7. allowable waveforms;
8. and other facilities.

C. Rule 21, on non-utility owned generation, is the basis for interconnection documents provided by the regulated utilities.

III. <u>Municipal Utilities</u>:

A. Sacramento Municipal Utility District (SMUD):

1. Not all of SMUD's documents were available at the time of this review. (See document list.) The document reviewed, Special Requirements – Generator Interconnection, describes SMUD's requirements in a detailed concise manner. (This document will be referred to as SR-GI.)

B. Los Angeles Department of Water and Power (LADWP):

1. INCOM is in the process of contacting LADWP for their input towards this effort.

IV. <u>Irrigation Districts</u>:

A. Imperial Irrigation District (IID):

1. The IID has no published documents on interconnection requirements. The Planning Department has been notified of this effort by CADER and may decide to participate in the future.

B. Other Districts: (future)

V. <u>Rural Electric Co-Operatives (REC)</u>:

A. Plumas-Sierra Rural Electric Cooperative:

1. Northern California co-ops, including Plumas-Sierra, generally follow PG&E's guidelines.

VI. Summary of Requirements:

A.	General Requirements	**SCE**	**SDG&E**	**PG&E**	**SMUD**
1.	Interconnection Studies	Yes	Yes	Yes	Yes
2.	Review and Approval of Design	Yes	Yes	Yes	Yes
3.	Right to Inspect Facilities: pre & post connection	Yes	Yes	Yes	Yes
4.	Signed Contract(s)/Agreement(s) before Connection	Yes	?	Yes	Yes
5.	Must meet all applicable codes and requirements of other authorities	Yes	Yes	Yes	Yes
6.	Provide Maintenance and Calibration/Test Reports and/or Witness Tests	Yes	Yes	Yes	Yes
7.	Provide Proof of Insurance	Yes	?	?	?
8.	Conduct Pre-Parallel Tests	?	?	Yes	Yes

B.	General Design Requirements	**SCE**	**SDG&E**	**PG&E**	**SMUD**
1.	Disconnect Required (M = manual; LB= Load break)	Yes M	Yes M, LB	Yes M	Yes M
2.	Delineated by Capacity (and/or Voltage)	Yes	Yes	Yes	Yes

C.	Operating Requirements that Affect Design	**SCE**	**SDG&E**	**PG&E**	**SMUD**
1.	Reactive Power and Voltage Control	Yes	Yes	Yes	Yes
2.	Power Quality	Yes	Yes	Yes	Yes

VII. Details of Requirements:

General Requirements

1. Interconnection Studies:

SCE:
Producer must " request a Method of Service (MOS) study to determine among other things, the availability of transmission capacity on the Edison system, the equipment necessary to interconnect the Producer's project to the Edison system, the breakdown of cost estimates for the interconnection, and the time necessary to build the interconnection facilities." Producer must provide all information and data necessary for MOS. Producer must pay SCE for cost of study.

SDG&E:
" The Producer is required to request an interconnection study as described in SDG&E's Rule 21 and/or the Agreement. An interconnection study can consist of a Preliminary Interconnection Study and/or a Detailed Interconnection Study." Producer must provide all information and data necessary for study. Producer must pay for study in advance.

PG&E:
Introduction to handbook mentions that any other requirements, in addition to those in the handbook, " will be identified through studies performed by PG&E prior to interconnection."

Also, in Section 1.6, it is stated that " Studies will determine whether PG&E will be required to add or modify its transmission and distribution system to interconnect the requesting party. Parties which interconnect are responsible for the cost of necessary studies. Interconnecting entities must also pay for, as special facilities, any additions or modifications to the PG&E system needed to connect the requesting party, and for those portions of the interconnection facilities owned and maintained by PG&E at the requesting party's request."

Rule 21 also states "The Producer shall advance to PG&E its estimated costs of performing a preliminary or detailed engineering study as may be reasonably required to identify (and) 'any' Producer-Related Utility system additions and reinforcements." It is implied that the Producer will provide all necessary information and data to PG&E in order for PG&E to conduct its studies.

SMUD:
Specific studies, such as stability and interconnection, are mentioned in the SMUD document "Special Requirements – Generator Interconnection." It is not explicitly mentioned, but it is assumed, that these and any other studies must be performed before interconnection is allowed. There is no mention of who bears the costs of these studies.

2. Review and Approval of Design:

SCE:
Specifically stated in Rule 21.

SDG&E:
Specifically stated in Rule 21.

PG&E:
Specifically stated in Rule 21.

SMUD:
Stated in SR-GI document.

3. Right to Inspect Facilities: Pre and Post Connection

SCE:
Specifically stated in Rule 21 and Agreements.

SDG&E:
Specifically stated in Rule 21.

PG&E:
Specifically stated in Rule 21, at least for Pre-Connection.

SMUD:
Stated in SR-GI document.

4. Signed Contracts/Agreements before Connection:

SCE:
Specifically stated in Rule 21 and handbook. These may include:
A parallel generation agreement, interconnection facilities agreement, departing load transition charge agreement, power purchase agreement, and standby service agreement.

SDG&E:
Rule 21 states only that final written approval to commence parallel operation must be given. The handbook briefly mentions power purchase and interconnection agreements, but does not state that these agreements are necessary.

PG&E:
Rule 21 states that " The Producer shall sign PG&E's written form of power purchase agreement or parallel operation agreement and a 'Standard Operating Agreement for Facilities 40kW and Larger' before connecting or operating a generating source in parallel with PG&E's system." Also "No generating source shall be operated in parallel with PG&E's system until the interconnection facilities have been inspected by PG&E and PG&E has provided written approval to the Producer."

SMUD:
Stated in SR-GI document.

5. Must meet all applicable codes and requirements of other authorities:

SCE:
Stated in handbook.

SDG&E:
Stated in Rule 21 (D.1.a.)

PG&E:
Stated in Rule 21 (A.3.)

SMUD:
Stated in SR-GI document.

6. Provide Maintenance and Calibration/Test Reports and/or Witness Tests:

SCE:
Stated in Rule 21 and handbook.

SDG&E:
Stated in Rule 21.

PG&E:
Stated in handbook.

SMUD:
Stated in SR-GI document.

7. Provide Proof of Insurance:

SCE:
Stated in handbook and Agreements.

SDG&E:
No mention in Rule 21 or handbook. May be part of Agreements.

PG&E:
No mention in Rule 21 or handbook. May be part of Agreements.

SMUD:
No mention other than statement of indemnity in Section A of SR-GI.

8. Conduct Pre-Parallel Tests:

SCE:
No mention in Rule 21. As stated in the handbook, "Edison reserves the right to inspect the Producer's facility and witness testing of any equipment or devices associated with the interconnection."

SDG&E:
As stated in Rule 21, D.2.c.: "The utility reserves the right to inspect the customer's facility and witness testing of any equipment or devices associated with the interconnection."

PG&E:
Mentioned in Rule 21 and in handbook (detailed descriptions of tests given.)

SMUD:
Stated in SR-GI document.

Design Requirements:

1. Disconnects:

SCE:
Handbook (Section 2.1.6) states " A manual disconnecting device which can be opened for line clearances must be provided. The form of this device will vary with the service voltage and capacity." For services of 200-amp capacity or less, Edison's metering facilities will be used for the disconnecting device.

SDG&E:
Rule 21 (Section D.1.c.) states: "A manual **load break** disconnect device shall be available at or near the customer's main service point(s). This disconnect device may be owned by either party but the utility must have preemptory control for utility outages or switching. The disconnect device must be capable of being locked in the open position if the customer has access to the disconnect device (see Section H.2.a.)." (Emphasis added to "load break.")

Rule 21 (Section H.2.a.) states: "A means of disconnection must be available on both sides of the utility metering; must be under the control of the utility; and shall be applied to all customers with parallel generation. This can be accomplished with switches, load break elbows, cutouts or secondary breakers. Customer disconnects can also be used provided that: (1) the switches meet with utility approval. , (2) the utility has pre-emptive control."

Similar language to the above is found in the handbook (Section 2.2.1).

PG&E:
Rule 21 (Section B.2.b.) has a table showing that all generation, regardless of capacity, must have an "Interconnection Disconnect Device."

Rule 21 (Section B.2.c.) states: " The Producer shall provide, install, own and maintain the interconnection disconnect device required by Section B.2.b at a location readily accessible to PG&E. Such device shall normally be located near PG&E's meter or meters for sole operation by PG&E. The interconnection disconnect device and its precise location shall be specified by PG&E." Also the Producer has an option to request PG&E to provide, install, own and maintain the disconnect device as "special facilities in accordance with Section F."

In the PG&E handbook, Section G1.1, Metering disconnects, also describes the requirement for **two gang-operated, lockable disconnects** "to facilitate establishing a visual open." Also described are the locations for these disconnects. Figures G1-2 and G1-3 show locations of these disconnects. (Emphasis added.)

SMUD:
Manual disconnects are required for all generation. Only disconnect devices specifically approved by SMUD may be used.

2. Requirements Delineated by Facility Capacity/Voltage:

SCE:
Rule 21 (Section C.2.) mentions requirements that vary for small (below 100 kW), medium (100-1000 kW) and large (above 1000 kW) facilities. These requirements "are contained in SCE's Requirements for Operating, Metering, and Protective Relaying for Non-SCE Owned Generating Facilities." (Note: the title of SCE's 1994 handbook is "Requirements for Operating, Metering, and Protective Relaying for Cogenerators and Small Power Producers." These are assumed to be the same document.)

Referring to SCE's 1994 handbook, Section 3.0, Protection and Operating Requirements, states: " Edison has established three different classes for Producer generation, each with distinctive protection and operating requirements. These classes are:

1. 200 kVA and over, with Edison-owned protection.
2. 200 kVA and over, with Producer-owned protection.
3. Less than 200 kVA."

It is also stated in the same Section, "… that these classes have been established for convenience and are based on urban/suburban circuits with normal load density. The final decision as to the requirements for each installation will be made depending on Producer load magnitude, the magnitude of other load connected to that circuit/system, available short circuit contribution, etc."

SDG&E:

The SDG&E handbook and Rule 21 (Sections E, F and G) breakdown the requirements according to capacity: less than 100kW, 100kW to 1 MW and greater than 1 MW.

PG&E:

Rule 21 (Section B.2.b) contains a table that summarizes the control, protection and safety general requirements according to capacity. The capacity levels are: 10kW or Less; 11kW to 40kW; 41kW to 100kW; 101kW to 400kW; 401kW to 1000kW and Over 1000kW. A note to this table states: " … For a particular generator application, PG&E will furnish its specific control, protective and safety requirements to the Producer after the exact location of the generator has been agreed upon and the interconnection voltage has been set."

The PG&E handbook uses other capacity levels, and also voltage levels, to differentiate design requirements for metering, protection and control. For new generation, metering requirements differ according to these capacities:

- 100kW or less;
- greater than 100kW and less than or equal to 1000kW;
- greater than 1000kW (with telemetering for generation 10,000kW or greater, and determined on a case-by-case basis for less than 10,000kW.)

Line protection requirements are delineated according to voltage level:

- 34.5kV or less;
- 44kV, 60kV or 70kV;
- 115kV;
- 230kV.

Generator protection requirements are delineated according to capacity:

- 40kW or less;
- 41kW to 400kW;
- 401kW and larger.

SMUD:

Table 1 of the SR-GI document summarizes the general interconnection requirements by capacity. (More specific requirements will be detailed later.)

Summary of Interconnection Requirements (Notes 1,2)

Requirement [(#) refers to notes]	Less than 10kW	10kW to <40kW	40kW to <100kW	100kW to <400kW	400kW to <1MW	1 to < 10 MW	10 MW +
Dedicated Transformer (12)		X	X	X	X	X	X
Disconnect Device (3)	X	X	X	X	X	X	X
Gen. Circuit Breaker	X	X	X	X	X	X	X
3 Ph Fault Interrupting Device (6)				X (11)	X (11)	X	X
Overvoltage Protection	X	X	X	X	X	X	X
Ph Overcurrent Prot.	X	X	X	X			
Undervoltage Prot.	X (8)	X (8)	X	X	X	X	X
O/U Frequency Prot.	X	X	X	X	X	X	X
Ground Fault Prot.			X (9)	X	X	X	X
Voltage Restraint/Volt. Control OC Relay or Impedance Relay					X	X	X
Manual Synch w/Gen. Synch Relay Supervision	X	X	X	X	X	X	X
Voltage and Power Factor Regulation			X	X	X	X	X
Utility Grade Relays (4)				X	X	X	X
Telemetering (5)						X	X
Time-of-Day Metering (10)	X	X	X	X	X	X	X
Reactive Demand/VARh Metering			X	X	X	X	X
Direct Phone Service	X	X	X	X	X	X	X
Remote Terminal Unit						X	X
Event Recorder (7)					X	X	X
Backup Telemetry (13)						X	X
Metering Data Recorder (MDR) (14)	X	X	X	X	X	X	X

Notes:

1. All requirements are based on generator nameplate, unless otherwise indicated.
2. The protection equipment listed fulfills only the minimum requirement. Additional protective device(s) will be required.

3. Disconnect devices are required on the line and load side of the metering units for transmission interconnections.
4. Utility grade relays are required for any transmission voltage (25kV and above) interconnection, regardless of generator output.
5. Requirement is based on deliveries to SMUD (greater than or equal to 1.0 MW), not necessarily generator nameplate. Additional time-of-day metering at generator for net power output may be required based on interconnection agreement and output option selected.
6. A three-phase fault-interrupting device is required at the point of interconnection (ownership change) with SMUD. It is usually located in the power producer's substation on the high side of the generator step-up bank if the interconnection does not involve a non-SMUD-owned tap line.
7. Event recorder required for unattended facilities with automatic or remotely initiated paralleling capability, or those that do not have the capability of retaining relay targets following a loss of power.
8. This requirement can be met by the contactor undervoltage release.
9. For induction generators 40kW < 100kW, ground fault detection requirements will be reviewed on a case-by-case basis.
10. Time-of-day/time-of-use metering may be required to administer forgiveness of standby tariff in conjunction with a demand energy schedule.
11. Fuses may be used if the generator breaker is equipped to protect against single-phasing conditions.
12. Generators less than 10kW generating at a secondary voltage level may not require an isolation transformer. However, this must be approved by SMUD after review of the project details.
13. Backup Telemetry is required for all RTU and telemetry installations.
14. Backup metering data recorders are required for all NUG interconnections regardless of generator rating. This recorder must have the ability to record parameters to allow calculation of the generator capacity factor if real time telemetry is not required.

Protection Requirements: Line and Generation

SCE:

Rule 21 (Section C.1) states in general terms the requirements for non-SCE-owned generation. The Producer's facility "shall be designed and operated so as to prevent or protect against the following adverse conditions on SCE's system. These conditions can cause electric service degradation, equipment damage, or harm to persons:

a. Inadvertent and unwanted re-energization of a SCE dead line or bus.
b. Interconnection while out of synchronization.
c. Overcurrent.
d. Voltage imbalance.
e. Ground faults.
f. Generating alternating current frequency outside permitted safe limits.
g. Voltage outside of permitted limits.
h. Poor power factor or reactive power (VARs) outside of permitted limits.
i. Abnormal waveforms."

The typical SCE protection requirements, as described in the handbook, have been summarized in the following table:

Table 1: Typical Protection Requirements for SCE, by Device Function

Synchronous Parallel Generation Edison owned Protection (>200 kVA)	Induction Parallel Generation Edison owned Protection (>200 kVA)	Synchronous Parallel Generation Producer owned Protection (>200 kVA)	Induction Parallel Generation Producer owned Protection (>200 kVA)	Parallel Generation Under 200 kVA
(Note 1)	(Note 1)	(Note 2 & 3)	(Note 2 & 3)	(Note 4)
(Re Fig. 5.1 in Handbook)	(Re Fig. 5.2)	(Re Fig. 5.3)	(Re Fig. 5.4)	(Re Fig. 5.5)
		Required,Line:	Required,Line:	Required:
SCE 52	SCE 52	Prod. 52	Prod. 52	Prod. Gen 52
Prod. 52 or DS	Prod. 52 or DS	25 (2: Line & Gen)	25 (Line)	47
25	25	51N	51N	27/59
51V or 67V	51, 51V or 67V	47	47 (2: Line & Gen)	81O/U
51N or 59G	51N or 59G	67V	81O/U	
27/59	27/59	81O/U	27/59	
81-O/U	81-O/U	27/59		
47/79	47/27	Suggested:	Suggested:	
78	32 (re Fig. 5.2)	51 (Line)	51 (Line)	
32 (re Fig. 5.1)		32 (Line)	32 (Line)	
		78 (Line)	51N (Line)	
		47 (Gen)	87 (Gen)	
		87 (Gen)	27/59 (Gen)	
		27/59 (Gen)	40	
		40	46 (Gen)	
		46 (Gen)	51V (Gen)	
		51V (Gen)		

Notes:

1. For interconnection voltages greater than 34.5 kV, Edison will install, own and maintain, at the Producer's expense, a parallel generation interconnection at the Edison point of interconnection. For interconnection voltages at 34.5 kV or lower, either the Producer or Edison, at the Producer's request, can install, own and maintain the interconnection facilities.

2. Limited to interconnection voltages of 34.5 kV and lower.

3. In specific installations, particularly with large generators (over 10,000 kVA), SCE may require specific additional protection functions.

4. Producer may be required to be served through a dedicated distribution transformer that serves no other customers. Also, inverter systems shall meet the requirements of

IEEE Standard 519-1992, “Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems.”

SDG&E:

In general, Rule 21 (Sections E, F and G) states that the utility shall provide and install metering for all generation regardless of capacity. All cost will be borne by the customer, except for certain customers under 20kW (see section J.1.d.)

Rule 21 (Section E.4) states: “ The customer will be required to provide suitable devices to ensure adequate protection for the following:

a. All faults on the customer’s system.
b. All faults on the utility’s system.
c. Backfeed or start-up of a customer’s generator(s) into a dead utility bus.”

Typical SDG&E protection requirements, as described in the handbook, have been summarized in the following table:

Table 2: Minimal SDG&E Protective Devices, by function

Generation < 100 kW	100kW to 1MW	Greater than 1MW
(Notes 1,2)		
51 (all phases)	51 (all phases)	51 (all phases)
27 (all phases)	27 (all phases)	51N/51G
81U	81 O/U	27/59
25 or equivalent	25	81 O/U
	46	25
		46
		Telemetering or Sup. Equip.

Notes:
1. For voltages less than or equal to 480, need dedicated transformer, except for generators less than 10kW or induction generators less than 100kW.
2. For induction generators less than 10kW, the protective devices are recommended, not required.

PG&E:

Rule 21, Section B.2.a, General: Control, Protection and Safety Equipment, states that: “ PG&E has established functional requirements essential for the safe and reliable parallel operation of the Producer's generation. These requirements provide for control, protection and safety equipment to:

1) sense and properly react to failure and malfunction on PG&E's system;
2) assist PG&E in maintaining its system integrity and reliability; and
3) protect the safety of the public and PG&E's personnel."

The following table, taken from Rule 21 (Section B.2.b.) lists "the various devices and features generally required by PG&E as a prerequisite to parallel operation of the Producer's generation:"

<u>Table 2, Control, Protection and Safety General Requirements (PG&E)</u>
By Generator Size (Note 1)

Device or Feature	10kW or less	11kw to 40kW	41kW to 100kW	101kW to 400kW	401kW to 1,000kW	Over 1,000kW
Dedicated Transformer (Note 2)	-	X	X	X	X	X
Interconnection Disconnect Device	X	X	X	X	X	X
Gen CB	X	X	X	X	X	X
Over-voltage Protection	X	X	X	X	X	X
Under-voltage Protection	-	X	X	X	X	X
Under/Over-frequency Prot.	X	X	X	X	X	X
Ground Fault Protection	-	-	X	X	X	X
Over-current Relay w/Voltage Restraint	-	-	-	-	X	X
Synchronizing (Note 3)	Manual	Manual	Manual	Manual	Manual	Automatic
PF or Voltage Regulation Equip.	-	-	X	X	X	X
Fault Interrupting Device (Note 4)				X	X	X

Notes:

1. Detailed requirements are specified in PG&E's current operating, metering and equipment protection publications, as revised from time to time by PG&E and available to the Producer upon request. For a particular generator application, PG&E will furnish its specific control, protection and safety requirements to the Producer after the exact location of the generator has been agreed upon and the interconnection voltage level has been established.
2. This is a transformer interconnected with no other Producers and serving no other Utility customers. Although the dedicated transformer is not a requirement for generators rated 10kW or less, PG&E recommends its installation.
3. This is a requirement for synchronous and other types of generators with stand-alone capability. For all such generators, PG&E will also require the installation of "reclose blocking" features on its system to block certain operations of PG&E's automatic line restoration equipment.
4. To be installed by the Producer at the point where his ownership changes with PG&E.

The PG&E handbook presents a comprehensive and detailed description of generation-entity metering, protection and control requirements. As this document is meant to give only a brief overview, the reader is referred to the handbook for a more complete narrative. Sections G1 (Revenue-Metering), G2 (Protection and Control), G3 (Operating Requirements), G4 (Operating Procedures) and G5 (Pre-Parallel Inspection) particularly pertain to generating facilities. Only Section G2 will be addressed here.

Section G2, on Protection and Control Requirements for Generation Entities, is broken down into nineteen subsections. A brief explanation of each subsection follows:

1. <u>Protective relay requirements</u>:
   Discusses reasons for requirements, general rules and requirements, tests and test reports.

2. <u>Reliability and redundancy</u>:
   General statement on reliability and redundancy. Specifically states that " Multi-function three-phase protective relays must have redundant relay(s) for backup."

3. <u>Relay grades</u>:
   Discusses industrial grade and utility grade relays and where each type may be used. Mentions list of PG&E approved relays. Requires prior PG&E approval of all relays specifications, performance tests and supporting data for relays not on approved list. Tables G2-3, G2-4 and G2-5 list relays approved by PG&E.

4. Line protection:
General discussion on line protection and coordination with PG&E.
Gives table (Table G2-1a) of minimum line protection:

Table G2-1a: Line Protection Devices (*minimal*)

Line Protection Device	Device No.	34.5kV or less	44kV, 60kV or 70kV	115kV	230kV
Phase Overcurrent (OC) (radial systems)	50/51	X	X		
Ground OC (radial systems)	50/51N	X	X		
Phase Directional OC	67		X (note1)	X	
Ground Directional OC or Transformer Neutral	67N 50/51N		X (note1)	X	X
Distance Relay Zone 1	21Z1		X (note1)	X (note1)	X
Distance Relay Zone 2	21Z2		X (note1)	X (note1)	X
Distance Relay Carrier	21Z2C			X (note1)	X
Ground Directional OC Carrier	67NC			X (note1)	X
Distance Relay Carrier Block	21Z3C			X (note1)	X
Pilot Wire	87L			X (note1)	X
Permissive Overreaching Transfer Trip (POTT) or Hybrid	21/67T			X (note1)	X
Direct Transfer Trip	TT	X(note2)	X(note2)	X(note2)	X(note2)

Notes:
1. May be required on transmission or distribution interconnections depending on local circuit configurations, as determined by PG&E.
2. Transfer trip may be required on transmission-level or distribution-level interconnections depending on PG&E circuit configuration and loading, as determined by PG&E. …(*see document for complete note.)*
3. Generator protection:
Discusses generator types, standards, and configurations.
States that all synchronous generators must have synchronizing relays and reclose blocking at the PG&E side of the line.
Table G2-1b lists minimal devices required. PG&E reserves right to require additional requirements, on a case-by-case basis. Each protective device is described in the text. Table G2-6 states the settings for over/under frequency and voltage relays for both transmission and distribution system interconnections.

Table G2-1b: Generator Protection Devices (*minimal*)

Generator Protection Devices	Device No.	40kW or less	41kW to 400kW	401kW and larger
Phase Overcurrent	50/51	X (note 2)	X (note 2)	
Overvoltage	59	X	X	X
Undervoltage	27	X (note 3)	X	X
Overfrequency	81O	X	X	X
Underfrequency	81U	X	X	X
Ground Fault Sensing Scheme (Utility Grade)	51N		X (note 4)	X
Overcurrent with Voltage Restraint/Voltage Control or Impedance Relay	51V 21		X (note 5)	X
Reverse Power Relay (No Sale)	32	X (note 6)	X (note 6)	X (note 6)

Notes:

1. (*refers to device number definitions and functions*.)
2. Overcurrent protection must be able to detect a line-end fault condition. A "*50/51*" relay which can see a line fault under sub-transient conditions is required. This is not required if a 51V relay is used.
3. For generators 40kW or less, the undervoltage requirement can be met by the contactor undervoltage release.
4. For induction generators and certified non-islanding inverters aggregating less than 100kW, ground fault detection is not required. For synchronous generators aggregating over 40kW, ground fault detection is required.
5. A group of generators, each less than 400kW but whose aggregate capacity is greater than 400kW, must have an impedance relay or an overcurrent relay with voltage restraint located on each generator greater than 100kW.
6. For "No Sale" generator installations, under the proper system conditions, a set of three single-phase, very sensitive reverse power relays, along with the dedicated transformer, may be used in lieu of ground fault protection. The relays shall be set to pick-up on transformer magnetizing current, and trip the main breaker within 0.5 second.

<u>7. Dedicated transformer</u>:
Discusses use and need for dedicated transformer.
"Generators of more than 10kW require the use of a dedicated transformer."
"Generators of 10kW or less and generating at a secondary voltage level may require a dedicated transformer. This need can be determined and identified in a detailed study."

Discusses requirement for high-side fault-interrupting device and possible use of lightning arrestors.

Figures G2-7 and G2-8 show recommended ground detection schemes for different service transformer circuits.

8. Manual disconnect switch:
Discusses number, uses, locations, specifications, and voltage-levels of switch(s).

9. Fault-interrupting devices:
"The fault-interrupting device selected by the Generation Entity must be reviewed and approved by PG&E for each particular application."

Discusses three basic types: circuit breakers, circuit switches and fuses.

In certain cases fuses are not allowed.

10. Synchronous generators:
Discusses applicable standards (American National Standards Institute & IEEE); range of operation (for voltage and frequency); synchronizing relays; frequency and speed control; excitation system requirements; voltage regulator requirements; power factor controller requirements; Power System Stabilizer (PSS) requirements; and event recorder requirements, if needed.

11. Direct digital control (DDC):
"Dispatchable generators larger than 10,000kW are required to have real-time direct digital control of unit output from the ISO Control Center."

12. Remedial Action Scheme (RAS):
"A RAS is a special protection system which automatically initiates one or more preplanned corrective measures to restore acceptable power system performance following a disturbance."
Describes generally what RAS is and whether RAS participation is required.

13. Induction generators:
Describes general reactive power requirements, and possible voltage and/or var schedule.

14. DC generators:
Discusses inverter types, capabilities, harmonic standards (IEEE 519), and stand-alone vs non-stand-alone operation.

15. Emergency generators:
Discusses two methods of transfer between PG&E's system and emergency generator: open transition and closed transition. Discusses implications of both types of transfer and corresponding specifications on maximum parallel times, relays settings, synchronization, notification/documentation and operation/clearances.

16. Parallel-only generation (No-Sale) :

Have to meet requirements similar to that of standard generation. May be allowed modification to ground detection scheme.

"Owners of Parallel-Only generators must execute a parallel-only operating agreement with PG&E prior to operation by the generation owner."

2.4kV & higher voltage taps:
Discusses additional requirements imposed on Generation Entities interconnecting at primary or transmission level voltages.

PG&E system changes:
Discusses modifications that may have to be performed on PG&E's system to accommodate generator interconnection.

17. Direct telephone service:
"The Generation Entity must obtain services from the local telephone company so that operating instructions from PG&E can be given to the designated operator of the Generation Entity…."

18. Standby station service:
The Generation Entity should contact the local PG&E representative if station standby service is desired.

SMUD:
Appendix B of the SR-GI document discusses specific minimum system protection requirements. The determination of what types of protective devices are required depends primarily on four factors:

1. Type and size of generator.
2. Location of generator on SMUD system.
3. Type of transformer connection utilized.
4. Ownership, maintenance, and operation of the inter-tie protective relaying and associated equipment.

Very specific descriptions and discussions are presented for the various types of generation, associated protection, protection schemes, equipment and operating requirements. It is best to refer directly to this document for detailed explanations. Two tables are presented, though, that summarize minimum basic protective devices and additional interconnection protective devices for voltages over 25kV. Figure 1 in the document shows a diagram of typical interconnection protection.

Table 1: Basic Interconnection Protective Devices (*minimal*)

Protective Device [(#) refers to notes]	Device No.	< 40kW	40 < 400kW	400kW +
Phase Overcurrent	50/51	X (1)	X (1)	X
Overvoltage	59	X	X	X

Undervoltage	27	X (2)	X	X
Overfrequency	81O	X	X	X
Underfrequency	81U	X	X	X
Ground Fault Protection (Utility Grade)	51N		X (3)	X
Overcurrent with Voltage Restraint or Voltage Control	51V		X (4)	X

Notes:

1. Overcurrent protection must be able to detect an end-of-line fault condition. An instantaneous overcurrent, which can detect a line-end fault under subtransient conditions, is required.
2. For induction generators rated 40kW and less, the undervoltage requirement can be met by the generator contactor undervoltage release if so equipped.
3. For induction generators rated 40 to 100kW, ground fault detection requirements will be reviewed on a case-by-case basis. Ground fault detection is required for synchronous generators over 40kW.
4. For generators rated 41 to 100kW, voltage restrained overcurrent requirements will be reviewed on a case-by-case basis.

Table 2: Additional Interconnection Protective Devices (*for voltages over 25kV*)

Protective Device	Device No.	Line Voltage (1)		
		69kV	115kV	230kV
Current Differential	87	X (3)	X	X
Phase Directional Overcurrent	67	X		
Ground Directional Overcurrent	67N	X	X	X
Distance Relay Zone 1	21-1		X	X
Distance Relay Zone 2	21-2		X	X
Distance Relay Zone 3	21-3		X	X
Backup Distance (4)	21B	X		
Breaker Failure	50/62BF	X	X	X
Permissive Overreaching Transfer Trip	POTT		X	X
Direct Transfer Trip (2)	DTT	X	X	X

Notes:

1. The choice of line voltage column is site specific.
2. May be required on transmission or distribution interconnections.
3. Current Differential required if interconnection is made using a dedicated 69kV line.
4. May be substituted with a second set of directional phase and ground overcurrent relays.

<u>Other Requirements that Affect Design:</u>

(This not a complete list. Besides operating requirements, other requirements regarding metering, communication and control will also affect the design of the interconnection. Please refer to the original documents for detailed information.)

1. Reactive Power and Voltage Control:
In some cases, there are requirements on generators, regardless of type or capacity, to provide reactive power and voltage control to the interconnected power system. The generator itself can meet these requirements if it has the capability. If the generator can not meet the requirements by itself, then adding other reactive support equipment (capacitors) or purchasing ancillary service from the utility or other suppliers may be necessary.

2. Power Quality:
Utilities require certain power quality standards to be met. These include power factor, harmonics and voltage fluctuations that interfere with service and communications.

Power factor requirements are handled by reactive power and voltage control.

The IEEE 519-1992 standard on harmonics has been generally accepted by utilities in the U.S. (Note: International standards on harmonics are different than the IEEE 519.)

Voltage fluctuations can be produced by electrical machinery (starting induction motors, induction generators), by power electronic switching (certain types of inverters/converters), or other means. Any generation facility that causes such interference is subject to disconnection from the power system until the condition causing the interference has been corrected. Generally these problems can be avoided in the first place by applying proper design techniques.

Summary of Interconnection Requirements of the Los Angeles Department of Water and Power: (as of June 1999)

The following information is a summary of LADWP's published document "Customer-Owned Parallel Generating Systems", May 1995.

Interconnection Agreements:
1. A Parallel Generation Interconnection Agreement is required before the generating facility may be connected.
2. The Department has a standard offer contract for interconnection agreements, however the customer may request a nonstandard agreement.

Interconnection Costs:
1. The customer will reimburse the Department for all expenses it incurs associated with the generation facility.

Transformer Requirements

1. The capacity of service required determines the transformer capacity and interconnection voltage levels. Higher capacity requires connection to higher primary voltages: < 500-kVA to 4800-v; 500 to 750-kVA to 34.5-kV; > 750-kVA to 34.5-kV. Capacities over 500-kVA require dedicated transformers.

Operating Requirements:

1. Facility must be operated accordance with the interconnection agreement, the Department's electric service requirements, Rules, Rate schedules and all other applicable codes and ordinances.
2. Customers shall not energize an unenergized Department line or transformer.
3. Customers shall not reconnect after a protective device has tripped unless the customer's system has been energized by the Department or the customer's system has been isolated from the Department's system.
4. The Department uses automatic reclosing of tripped lines.

Metering

1. Requirement that the Department provide metering.
2. Department must approve metering equipment drawings before installation.

Inspections

1. Department maintains right to verify all conditions are met.
2. Customer must obtain approval from code enforcement and permitting agencies before the Department will permit connection.

Liability

1. The customer is liable for any damage to Department-owned equipment or other customer equipment as a result of misoperation or malfunction of the generating facility.
2. The Department assumes no responsibility for the protection of the facility's generator or electrical system.

Disconnection of Customer's Generation

1. The Department reserves the right to disconnect the generating facility under certain specific conditions. (See document for conditions.)

Generator Disconnects

1. Customer will furnish, install and maintain circuit disconnect devices as required by the Department.
2. Disconnect devices shall use visually verifiable air gaps and shall be lockable in the open position.
3. The Department-required disconnect device shall not be fused unless approved by the Department.
4. The Department shall have access to the disconnect device at all times and under all conditions.

Protective Schemes
1. The generating facility must use protective equipment.
2. Generally the Department will provide and install, at the customer's cost, the required protective equipment. Where mutually agreeable, the customer may provide and install the equipment, as specified by the Department, for certain generators: synchronous generators rated less than 300 kVA and induction generators rated less than 400 kVA when supplied by the Department's 4800-v system, or synchronous generators rated less than 400 kVA and induction generators rated less than 600 kVA when supplied by the Department's 34,500-v system.
3. The Department will install ground fault protection equipment, at the customer's cost, for facilities rated 1 MW and above, and interconnected with the Department's 34.5-kV system. The Department may specify this requirement for facilities less than 1 MW.
4. The electrical rating (capacity) of the generating facility will determine, in part, the protection requirements for the facility.
5. Typical protection equipment requirements include, but are not limited to: over and under voltage protection; over and under frequency protection; tripping batteries, circuit breakers and battery chargers.
6. The generating facility's circuit breakers must positively disconnect under all conditions. A charger assisted, uninterrupable dc power source may be necessary.
7. The Department reserves the right to review and approve any interconnection scheme involving customer initiation of the interconnecting breaker controls.
8. Protection equipment shall be readily accessible to the Department for periodic inspection.

Telemetry
1. The facility must have an operating telephone service when required by the Department.
2. For installations rated 1 MW or more, the customer must install telemetering equipment for continuous output of information to the Department's Energy Control Center.

Maintenance
1. The Department will maintain Department installed protective equipment.
2. For customer installed protection equipment, the customer will provide monthly maintenance reports.
3. For generation rated 500 kVA or more, maintenance must be scheduled in advance with the Department.

Records
1. The customer must provide accurate records of the facility. The document lists what information should be documented.
2. The Department reserves the right to review these records.

Specifications

1. The generating facility must adhere to the following specifications:
   a. Frequency- 60 Hz
   b. Signal Distortion- limited to 5% on voltage, 25% on current
   c. Power factor- for generating systems < 1 MW: not less than 85% lagging
      - for over 1 MW: not less than 99.5% lagging or more than
      - 100.5% leading.
2. Protective equipment relays used to open and close generator circuit breakers shall operate with the following specifications:
   a. Under-voltage (device 27): 92-v or higher, maximum time delay of 2.0 seconds;
   b. Over-voltage (59): 138-v or less, maximum time delay of 2.0 seconds;
   c. Under-frequency (81U): 57 Hz or higher, maximum delay of 2.5 seconds;
   d. Over-frequency (81O): 61 Hz or less, maximum delay of 2.5 seconds.

Testing and Evaluation

1. The customer must test the generating facility before interconnecting and provide written certification to the Department that the generating facility meets the Department's specifications.
2. The Department reserves the right to test the generating equipment before approving connection and the right to periodically monitor onsite operation of the equipment.
3. If the Department determines the facility does not meet the Department's specifications, the Department may require the customer to disconnect the facility and make corrections.
4. Where the customer installs protective equipment, the customer shall have the equipment tested at two-year intervals, at the customer's cost, by a Department approved testing agency. The customer will arrange contracts with, and arrange payment to, the approved agency, and shall schedule testing to be completed within the two-year interval. The results of the tests shall be provided in writing by the testing agency to the Department.

Generators

1. Generators operated by customers must be connected on the customer's electrical system on the load side of the Department's metering equipment at a Department approved location.
2. Single-phase generators are limited to 20 kVA for each unit. There are restrictions on connecting multiple single-phase units to provide a balanced three-phase supply.
3. For synchronous generators, automatic synchronization is preferred. Manual synchronization with relay supervision is acceptable.
4. Voltage regulation must be provided.
5. Induction generators may need capacitors to correct power factor.
6. Generator installations rated 750 kVA or less may be required to meet conditions and specifications normally required for larger generators. This will depend on the type of equipment used and the interconnection scheme.

Inverters

1. Inverters may be used to interconnect.
2. An isolation transformer is required.

3. Inverters are required to be line commutated and line feeding.
4. The inverter must be prevented from connecting if the inverter is not synchronized to the Department's system.
5. The inverter must ramp in.
6. The inverter must operate as a current source.

Misc
1. The document has two interconnection diagrams: one for a customer-owned transformer and one for a Department-owned transformer.

Interconnection Requirements of Los Angeles Department of Water and Power (LADWP)

Summary of LADWP Interconnection Requirements: (as of June 1999)

The following information is a summary of LADWP's published document "Customer-Owned Parallel Generating Systems", May 1995.

Interconnection Agreements:
3. A Parallel Generation Interconnection Agreement is required before the generating facility may be connected.
4. The Department has a standard offer contract for interconnection agreements, however the customer may request a nonstandard agreement.

Interconnection Costs:
2. The customer will reimburse the Department for all expenses it incurs associated with the generation facility.

Transformer Requirements
2. The capacity of service required determines the transformer capacity and interconnection voltage levels. Higher capacity requires connection to higher primary voltages: < 500-kVA to 4800-v; 500 to 750-kVA to 34.5-kV; > 750-kVA to 34.5-kV. Capacities over 500-kVA require dedicated transformers.

Operating Requirements:
5. Facility must be operated accordance with the interconnection agreement, the Department's electric service requirements, Rules, Rate schedules and all other applicable codes and ordinances.
6. Customers shall not energize an unenergized Department line or transformer.
7. Customers shall not reconnect after a protective device has tripped unless the customer's system has been energized by the Department or the customer's system has been isolated from the Department's system.
8. The Department uses automatic reclosing of tripped lines.

Metering

3. Requirement that the Department provide metering.
4. Department must approve metering equipment drawings before installation.

Inspections
3. Department maintains right to verify all conditions are met.
4. Customer must obtain approval from code enforcement and permitting agencies before the Department will permit connection.

Liability
3. The customer is liable for any damage to Department-owned equipment or other customer equipment as a result of misoperation or malfunction of the generating facility.
4. The Department assumes no responsibility for the protection of the facility's generator or electrical system.

Disconnection of Customer's Generation
2. The Department reserves the right to disconnect the generating facility under certain specific conditions. (See document for conditions.)

Generator Disconnects
5. Customer will furnish, install and maintain circuit disconnect devices as required by the Department.
6. Disconnect devices shall use visually verifiable air gaps and shall be lockable in the open position.
7. The Department-required disconnect device shall not be fused unless approved by the Department.
8. The Department shall have access to the disconnect device at all times and under all conditions.

Protective Schemes
9. The generating facility must use protective equipment.
10. Generally the Department will provide and install, at the customer's cost, the required protective equipment. Where mutually agreeable, the customer may provide and install the equipment, as specified by the Department, for certain generators: synchronous generators rated less than 300 kVA and induction generators rated less than 400 kVA when supplied by the Department's 4800-v system, or synchronous generators rated less than 400 kVA and induction generators rated less than 600 kVA when supplied by the Department's 34,500-v system.
11. The Department will install ground fault protection equipment, at the customer's cost, for facilities rated 1 MW and above, and interconnected with the Department's 34.5-kV system. The Department may specify this requirement for facilities less than 1 MW.
12. The electrical rating (capacity) of the generating facility will determine, in part, the protection requirements for the facility.

13. Typical protection equipment requirements include, but are not limited to: over and under voltage protection; over and under frequency protection; tripping batteries, circuit breakers and battery chargers.
14. The generating facility's circuit breakers must positively disconnect under all conditions. A charger assisted, uninterrupable dc power source may be necessary.
15. The Department reserves the right to review and approve any interconnection scheme involving customer initiation of the interconnecting breaker controls.
16. Protection equipment shall be readily accessible to the Department for periodic inspection.

Telemetry

3. The facility must have an operating telephone service when required by the Department.
4. For installations rated 1 MW or more, the customer must install telemetering equipment for continuous output of information to the Department's Energy Control Center.

Maintenance

4. The Department will maintain Department installed protective equipment.
5. For customer installed protection equipment, the customer will provide monthly maintenance reports.
6. For generation rated 500 kVA or more, maintenance must be scheduled in advance with the Department.

Records

3. The customer must provide accurate records of the facility. The document lists what information should be documented.
4. The Department reserves the right to review these records.

Specifications

3. The generating facility must adhere to the following specifications:
   d. Frequency- 60 Hz
   e. Signal Distortion- limited to 5% on voltage, 25% on current
   f. Power factor- for generating systems < 1 MW: not less than 85% lagging
      - for over 1 MW: not less than 99.5% lagging or more than
      - 100.5% leading.
4. Protective equipment relays used to open and close generator circuit breakers shall operate with the following specifications:
   e. Under-voltage (device 27): 92-v or higher, maximum time delay of 2.0 seconds;
   f. Over-voltage (59): 138-v or less, maximum time delay of 2.0 seconds;
   g. Under-frequency (81U): 57 Hz or higher, maximum delay of 2.5 seconds;
   h. Over-frequency (81O): 61 Hz or less, maximum delay of 2.5 seconds.

Testing and Evaluation

5. The customer must test the generating facility before interconnecting and provide written certification to the Department that the generating facility meets the Department's specifications.
6. The Department reserves the right to test the generating equipment before approving connection and the right to periodically monitor onsite operation of the equipment.
7. If the Department determines the facility does not meet the Department's specifications, the Department may require the customer to disconnect the facility and make corrections.
8. Where the customer installs protective equipment, the customer shall have the equipment tested at two-year intervals, at the customer's cost, by a Department approved testing agency. The customer will arrange contracts with, and arrange payment to, the approved agency, and shall schedule testing to be completed within the two-year interval. The results of the tests shall be provided in writing by the testing agency to the Department.

Generators

7. Generators operated by customers must be connected on the customer's electrical system on the load side of the Department's metering equipment at a Department approved location.
8. Single-phase generators are limited to 20 kVA for each unit. There are restrictions on connecting multiple single-phase units to provide a balanced three-phase supply.
9. For synchronous generators, automatic synchronization is preferred. Manual synchronization with relay supervision is acceptable.
10. Voltage regulation must be provided.
11. Induction generators may need capacitors to correct power factor.
12. Generator installations rated 750 kVA or less may be required to meet conditions and specifications normally required for larger generators. This will depend on the type of equipment used and the interconnection scheme.

Inverters

7. Inverters may be used to interconnect.
8. An isolation transformer is required.
9. Inverters are required to be line commutated and line feeding.
10. The inverter must be prevented from connecting if the inverter is not synchronized to the Department's system.
11. The inverter must ramp in.
12. The inverter must operate as a current source.

Miscellaneous

1. The document has two interconnection diagrams: one for a customer-owned transformer and one for a Department-owned transformer.

Appendix 2. Other Interconnection Efforts Outside California

Regulatory and Legislative Policy Issues

At present, utility interconnection requirements for CHP and other distributed generation equipment can be characterized as non-standardized, outdated, and often overly stringent. The lack of standards pose technical, economic and legal barriers to entry for small-scale grid-connected generation. As a result, uncertainty and arbitrariness associated with these requirements have dampened CHP market growth.

First, they increase project costs across the value chain – the end-user, the equipment vendor, the installer, the owner, and the operator (i.e. end-user, independent energy services company, utility, etc). Second, they make it very difficult for equipment manufacturers to produce a modular package. Whether the on-site technology is a micro-turbine, fuel cell, small gas turbine, or diesel engine-generator set, the lack of uniform interconnection standards hampers the efforts of CHP or other DG equipment manufacturers to realize economies of scale. Thus, the lack of uniformity from state to state, as well as from utility to utility within a given state, discourages the economic business case for on-site generation, no matter the market segment or type of end-use application.

Typical utility interconnection requirements tend to treat small-scale customer-owned generation the same way they treat large-scale PURPA facilities. These utility guidelines often define customer-owned generation by size of generation (MVA), and location in the grid (e.g. Voltage level). The guidelines tend to be classified as 'non-utility owned', or 'customer-owned', or 'on-site dispersed generation'; and are usually subdivided into three, four, or five increasingly complex interconnection agreements depending on the unique character of the specific utility grid. In general, guidelines were formally documented as a result of requirements stemming from PURPA, in 1978. Further revisions and additions to these guidelines were the result of both an increasing numbers of merchant independent power producers, and smaller on-site, customer-owned generation.

Regulatory and legislative interconnection policy initiatives, although not yet mainstream, are gaining momentum due to efforts in a few states. The regulatory treatments thus far have addressed policy matters as they pertain to safety, reliability, utility interests in contractual and operational integrity, customer requirements for ease of DG acquisition and installation, and equipment sellers' need for uniform national standards.

Regulatory commissioners and their staff tend to be saddled with a heavy workload that spans several regulated industries. Additionally, many do not have technical backgrounds or in-depth power industry expertise. Legislators and their staff possess an even broader agenda in comparison to regulators, so they are even more constrained in their ability to learn about how the power industry works, and what DG or interconnection legislative policy is required. As a result, DG in general, and interconnection in particular, has thus far suffered a regulatory and legislative policy gap. The policy gap is in part due to a lack of consistent, concise, objective, and intellectually sound message from the stakeholders. Trade groups such as the Distributed Power Coalition of America (DPCA) and the U.S. Combined Heat and Power Association (U.S.CHPA) provide a more unified industry message of both education and advocacy to policymakers.

Market Barrier Impact

The degree to which various utility-specific interconnection requirements have been revised and expanded has often been directly related to the local marketplace activity in on-site generation. Utility sponsored interruptible rate programs that reward peak shaving, load curtailment, and peak capacity solutions have developed alongside end-user focused peak shaving projects. Both applications have generally been based on traditional gas or diesel engine-generator sets, where the all-in embedded cost to interconnect has not often been substantial enough alone to affect a given project's feasibility. Such projects tend to range from 500kW to 5MW, and depended on important feasibility factors such as the customer load profile, utility rate structure, capital equipment cost, variable operation & maintenance cost, utility incentives, financing options, and standby power value.

The cost elements required to comply with existing utility interconnection requirements consist of a custom engineering effort and a lengthy negotiation process between the utility, the equipment providers, and project consulting engineers (often utilized due to the customized nature of each project). In order to gain interconnection compliance, each project developer must submit, review, and often modify system interconnection designs, one-line diagrams, device-level equipment specifications, and wiring diagrams. In other words, the conceptual design for the intended application, as well the actual interconnection device specification must be approved before such equipment is procured and installed. After the design and devices are approved, then site inspections are required, which are coordinated with the project developer, owner, and the utility. Whether or not the costs incurred by this process are passed on to the customer or carried by the utility, they often represent an unnecessary and substantial burden on utility personnel and the customer.

Review of Key Industry Efforts Outside California

EDISON ELECTRIC INSTITUTE (EEI)

EEI has organized a Distributed Resources Task Force, to enable member companies and affiliates the opportunity to make informed decisions about DG. The main thrust of EEI's task force is on education, analysis, and policy. The task force is particularly interested in providing strategic information regarding the potential role and implications of DG within the context of a changing business environment for electric service providers. The task force will develop and recommend policy actions to the EEI Board of Directors to help resolve economic and policy issues. The task force includes a working group named 'Planning, Operations, Interconnections, Environmental, Siting, Codes & Standards for DR' (Distributed Resources) with active representation from at least six utilities. The group has identified several project goals, to be completed in 1999. These goals were presented publicly by the working group co-chair Mr. Murray Davis, Detroit Edison at the Distributed Power Coalition of America (DPCA) 2nd Annual Meeting held in Washington, D.C. on November 12th & 13th 1998, and by Ken Hall of EEI, at the first IEEE SSC21 meeting.

The goals are:

(1) Catalogue and critique national and international standards on interconnection, including building codes and ancillary issues such as grounding.
(2) Collect and summarize existing utility interconnection requirements.
(3) Identify the variations in distribution configurations, protections, and other parameters used on primary and secondary systems in North America.
(4) Classify Distributed Resources (DR) technologies into a reasonable number of types and ratings for use in subsequent studies.
(5) Review potential technical benefits provided by DR to the utility, (e.g. voltage regulation, flicker, and harmonic reduction).
(6) Review limits to penetration of DR on a feeder (e.g. due to protection conflicts, voltage disturbances upon tripping, or on instability caused by overlapping of voltage regulators.)
(7) Choose a particular feeder for more detailed study.

The EEI DR Working Group has defined several parameters of its study, in accordance with the stated goals. First, an extensive list of some 29 issues pertaining to DG system protection and coordination has been compiled. Second, five different circuit configurations have been recommended for further study. Third, the study has been designed to include a measure of sensitivity to the distribution circuit, based on variations to several study variables. For example, the study includes different numbers, sizes, and types of DG technology. It also includes different feeder/circuit locations, X/R ratios[5], circuit length (i.e. rural vs. urban, low vs. high density loads, mixture of cable and overhead lines), heavily vs. lightly loaded conditions, unbalanced loads, and variations to substation voltage regulation devices.

Further details pertaining to EEI's DG interconnection initiatives have not been made available outside of its membership, and it is expected that the results of its studies will remain proprietary, in accordance with its standard practice.

[5] The X/R ratio is the ratio of reactance to resistance, either of the system or of individual equipment. This ratio is widely used in electrical engineering design and analysis.

ELECTRIC POWER RESEARCH INSTITUTE (EPRI)

EPRI has embarked on a wide range of DG interconnection research projects that specifically address interconnection requirements, system modeling, communications and control requirements, and interconnection hardware development. The research scopes will be funded collaboratively and scheduled in phases that began in mid-1997.

An initial interconnection project (Integration of Distributed Resources in Electric Utility Systems: Current Interconnection Practice and Unified Approach, TR-111489, Nov. 1998) was contracted to Power Technologies, Inc. The scope of work included a survey of 11 utility interconnection guidelines. The utilities surveyed were AEP, Cinergy, Duquesne Power & Light, NSP, Oglethorpe, PP&L, PECO, PEPCO, PS Co. of Colorado, SCE, and Tri-State G&T. Each guideline was reviewed in terms of both existing and planned requirements. It incorporated issues such as the type of protective relays utilized, size classes of DG units, step-up transformer winding configuration, the use of a dedicated transformer, utility transfer-trip requirements, and other essential details.

A key finding was that most interconnection standards focused almost entirely on the size and type of generator, but little on the characteristics of the distribution system at the point of interconnection. It was further stated that while size is an important consideration, it is not the entire picture and in fact, many requirements could be waived if the utility system is electrically stiff[6] in relation to the applied DG unit.

The EPRI study also presents a unified interconnection approach for DG that is intended to coalesce appropriate existing practices into a methodology that considers both distribution system and DG system characteristics. EPRI viewed the results as consistent with a prudent level of protection so that DG units could operate safely, avoid creating negative impacts on other loads and minimize costs by the eliminating unneeded protection.

EPRI has also developed a system simulation project, so that DG models can be used in existing utility system simulation tools. Through work co-funded by EPRI and Ontario Hydro Technologies, cases were run to determine fundamental system impact issues, and results were aggregated with recommendations in a report for utility transmission and distribution planners. EPRI's communication and control project involved development of functional definitions for use in determining communication and control requirements, with user tools to assist in design of specific communication and control strategies and

[6] A stiff utility system is one where the voltage doesn't change very much with load current. A weak system will exhibit large voltage variations with changing load current. An example would be where a large induction motor is started across the line (full line voltage.) On a stiff system other customers on the same line will not see any major change in voltage (dimming of lights, flicker, etc.) On a weak system, customers will see these effects. Whether a system is weak or strong depends on what measures the utility has taken to ensure voltage stability and what the impedance is between the customer and the system. In the case of motor starting, if the feeder conductor is not sized properly (for voltage drop), then the voltage at the receiving end (at the motor or other customers) will be less because of the voltage drop across the impedance. The NEC generally requires this drop to be less than 3 to 5%.

systems. Technology development needs may be a follow-up project, as well as dynamic simulation of DG on utility distribution systems. Specific results other than those cited from public presentations have not been made available, due to the proprietary nature of the projects for membership.

NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISSIONERS (NARUC)

Its Energy Resources and the Environment Committee have fostered NARUC's interconnection activity. The study of DG market barriers was passed as a resolution during NARUC's July 1998 summer meeting, where the organization officially recognized the benefits of smaller scale generation. The most recent chair of this Committee is R. Brent Alderfer, Commissioner of the Colorado Public Utility Commission. Mr. Alderfer has been a strong proponent of DG who has spoken around the country on the subject. Through his leadership in NARUC, Mr. Alderfer has assisted in the development of two specific, state-oriented regulatory activities for DG. One of the two activities is a research project entitled "Model Utility Interconnection, Tariff and Contract Provisions for Small Scale and Customer Owned Generators."

The stated project goal is to research and develop interconnection, tariff, and contract provisions for DG, in a form that can be used as a standard or model for adoption by state utility regulators. The project will review existing technical standards, salient state regulations and applicable contractual provisions. The project will also incorporate, develop, and compile the best of these elements into a final model provision. It should be noted that the tariff provisions in the project are limited to monopoly utility tariffs. They will not address unbundling, access or pricing issues for sales into a competitive power exchange market. Also, the project will address at least three generation sizes: less than 10kW, 10kW to 100kW and 100kW to 1MW. Specific deliverables of the project are:

(1) Technical interconnection standards for parallel electrical interconnection to the utility;
(2) Tariff provisions covering the sale of power to the utility and the purchase of power or grid back-up from the utility on an equitable basis;
(3) Contract terms and conditions governing the dealings between the utility and the interconnected generator.

The project delivery schedule requires presentation of the final model provisions at the NARUC annual meeting in November 1999. The study is designed to serve as the model, or template for consideration and implementation in all fifty states. The resources allocated, however, are modest and may not match the ambitious scope of the study, but it may nonetheless catalyze auxiliary efforts that would seek to extend the NARUC study by building on this initial work.

Review of Major State Policy Initiatives

NEW YORK PUBLIC SERVICE COMMISSION

The State of New York Department of Public Service launched its interconnection investigation at an 'initial all interested parties scoping meeting' held on August 28, 1998. The investigation was requested by the Public Service Commission (PSC) Chair Maureen O. Helmer, "to examine the interconnection issues of small distributed generating facilities for the purposes of streamlining and standardizing those requirements."

Accordingly, a series of meetings have been held since the initial meeting, and several more are officially slated as part of the investigation. The proceedings have attracted much interest from utilities, manufacturers of DG equipment, and other stakeholders. In spite of the best efforts of working group members to develop a consensus position, participants have exhibited some reluctance to yield or compromise on specific policy positions.

The meetings have been organized into two separate working groups – technical and non-technical policy. PSC staff has facilitated the meetings, with active support from numerous volunteer chairs and group members. The PSC staff has envisioned an informal five to six month collaborative process, in order to reach consensus on both technical and non-technical policy issues. Interested parties have conducted work thus far with guidance from PSC staff through several workshops, emails, and conference calls. The PSC has outlined its plans to submit a six-month phase one report in mid 1999, a phase two report by September 1999, and a plan to address remaining issues by October 1999.

The analytic approach to the policy issues includes several important assumptions and drivers, each with its own merits. The scope is technologically comprehensive, but narrow in its size and network topography dimension. The PSC has correctly defined equipment classes as inverter, induction, synchronous, and hybrid-based. However, the committee has limited its scope to systems less than 300 kW attached to a radial feeder connection. This limits applicability to only one subset of DG interconnection. Based on the activity thus far, the draft interconnect standards developed by this group appear to be stringent and limiting. Several specific aspects have the potential, whether intended or not, to keep the cost of DG uneconomical. A notable reduction of the full-in interconnection cost barrier would not be an outcome, based on the current interconnection draft. Rather, the cost barriers may remain the same as they are now unless further consensus building efforts change course.

TEXAS PUBLIC UTILITY COMMISSION

Although several state regulatory jurisdictions could have initiated investigations concerning peaking capacity availability due to last summer's problems, few Public Utility Commissions (PUCs) did so. The Texas PUC not only launched such an investigation, but had the foresight to recognize the need for an interconnection standard, and to begin the development process in earnest. The Texas PUC issued Project No.

19827, “Investigation into the Adequacy of Capacity for 1999 and 2000 Peak Periods”, to insure that electric utility planning was adequate for the coming years. On October 13th, 1998, the PUC held a Load Management Workshop as part of its investigation. Many resource options were presented and discussed by equipment vendors, consulting engineers, and energy service companies. The topic of interconnection emerged as vital issue, one that would require a regulatory policy action by the PUC in order to carry out a group load management program as outlined in the investigation.

As a result of the Load Management Workshop, PUC Chair Pat Wood, III requested that the PUC staff “begin a collaborative implementation effort to develop a state-wide, standardized interconnection and net metering agreement to enable renewables and stand-by generation under a certain size to interconnect with clear standards and procedures that ensure safety and reliability … to be completed by December 18th, 1998."

Accordingly, on November 9th the PUC staff conducted an Interconnection Workshop on the technical matters of interconnection. The Technical Task Force developed a draft document.

A separate non-technical, policy Task Force was established in order to define and frame the major policy issues. It was recognized that the time-table of the PUC’s Investigation would not allow for a robust analysis. The Policy Task Force convened by email and conference call. Over-riding principles of interconnection standards were stated:

(1) Public safety must not be compromised
(2) Electric Service must not be degraded
(3) Interconnection standards must not be overly burdensome
(4) Regulated services must be offered on a nondiscriminatory basis
(5) Costs must be clearly identified and borne by those who benefit
(6) Market forces should be relied on to the extent allowed under current law

Stated policy matters were also presented:

(1) Resource potential
(2) Resource ownership
(3) Resource classification and acquisition
(4) Location and value
(5) Cost allocation and unbundling
(6) Environmental permitting
(7) Insurance
(8) Standard contract and contract term
(9) Net metering
(10) Enforcement and appeals

The draft document entitled “1999 Interconnection Guidelines for Distributed Generation in Texas” was presented to the PUC and was incorporated into a PUC Staff Report that also included many written comments from interested parties. The PUC effort has been led by the Office of Policy Development's Nat Treadway.

On February 4th, the PUC adopted interconnection guidelines for DG. This represents an important result for the other efforts now under way, and could provide other states a benchmark for the interconnection standards development process. The PUC staff will monitor the application of the guidelines through Project No. 20363 "Investigation into Distributed Resources in Texas", which enlarges the scope of interconnection beyond the original investigation limited to near – term peaking capacity adequacy. The Commission has outlined several matters for the PUC staff to accomplish:

(1) Identify the contact person at each utility responsible for interconnection at the distribution voltage level
(2) Notify the commission when a request for interconnection has been initiated
(3) Monitor the development of national interconnection standards
(4) Report back to the Commission as necessary under Project No. 20363

The Commission has also requested that staff develop a standard contract for DG, so that transaction costs are reduced. The staff has proposed an outline to reach such a simplified document. First, identify a sample contract that would provide a starting point and distribute this to all interested parties for review. Second, summarize and distribute the comments following sample document review. Third, conduct a workshop and/or conference calls. Fourth, propose a standard contract for Commission approval.

Discussion of Interconnection Initiatives

Of all the formal initiatives outlined, the Texas interconnection guidelines represent the best near-term policy result to date. The Texas initiative was motivated by a formal investigation to determine possible courses of action so that a power shortage could be avoided in the near term. The Texas review of an interconnection standard was driven by a need to solve a possible problem. By framing the interconnection issue in a tactical, operational and near-term manner, the Texas PUC established a more narrow policy treatment, but clearly demonstrated that it understands the reasons for accommodating and supporting CHP and other forms of distributed generation. The IEEE SCC21 interconnection standard project is likely to become the de facto governing document. Respondents to the Texas and New York process recommended that each state adopt the IEEE standard once it is completed.

The Texas initiative, by design, did not result in an interconnection standard. Rather, an interconnection guideline was pursued and adopted. The guideline will not have the force of a formal Commission Ruling, but it does signal the Commission's intent to limit barriers to the interconnection of DG. A formal rulemaking procedure for standards may take place at a later date. The Texas guidelines, as compared to New York's draft version at the time of this writing, are less restrictive. The Texas version incorporates DG from 60kW to 10MW. New York's are limited to a 300kW size, with only one network topography (radially-connected feeders). Moreover, the Texas PUC staff has recommended that the Commission authorize the regulated utilities to pursue multiple year contracts for safe, reliable, and economical DG outside the formal resource solicitation process with non-regulated entities.

The Texas guideline report contains additional positive wording indicative of forward-thinking policy for DG. First, the report characterizes DG as both a demand-side and supply-side resource, which implies the need for multiple year contracts for DG that are negotiated in market-based terms. Second, location specific valuation of DG as a concept is supported by the PUC, so investigations into pricing signal methodologies that are based on geography-based economic criteria have been recommended. Third, the PUC has requested that near-term DG projects be studied for interconnection guideline compliance, as well as the analysis of project operation and ownership. Finally, investigation into the role of the ERCOT ISO on the control of DG has been recommended.

Limitations exist in the Texas guideline, not due to oversight, but related to the scope and approach taken. Such items will become emerging issues, and will require stakeholders to take a more active role. The New York process is structured to include all technologies, existing and emerging, including smaller-sized DG units. Unlike the broad scope of New York's effort, the Texas guideline focused on commercially available generation technology. The intent is to develop an interconnection guideline for near-term impact. The next step for Texas is to begin the process to expand technical requirements for various sizes and types of DG technology more clearly. In this context, the Texas guideline should define these categories similar to the way they are defined in the New York draft, while at the same time refrain from capping the upper limit or network topography as in New York.

The New York PSC initiative, as described above, may not have the desired effect of instilling predictability to the DG community. Instead, the benefits that stem from the standardization of design, installation, and operation of interconnected DG may not gain acceptance. As a result, modular, unitized mass production and mass deployment will be difficult. Hence the learning curve and long-term unit costs may not be driven down in New York.

Stakeholders should consider the merits of a performance-based standard where specific requirements depend on the impact the generation has on the power system, with variations for interconnect voltage. The requirements should be transparent to the type of generation or power converter technology used. This may be difficult to do initially because of the lack of experience with these technologies (especially static power converters) and because of the existing mind-set of stakeholders. Requirements should not be based on arbitrary numbers (as they are now with set capacity levels) but on sound technical reasoning, backed by experience or studies.

The initial stages of consensus building will include much education and discussion of experiences with the newer technology and utility systems. All DG stakeholders through a campaign of briefing packets, white papers, workshops, fact sheets, and testimony are working to support education of key decision-makers on the importance of interconnection policy.

NOTE ABOUT ON-LINE ELECTRONIC VERSION OF PUBLICATION # 700-00-010

Appendices # 3, 4, 5 and 6 are not available in an electronic version because they contain FAXes and other documents that could not be replicated into Adobe Acrobat PDF format.

Copies of these Appendices may be obtained from the Energy Commission Library by calling 916-654-4292.

Commission Webmaster

Appendix 3. New York State Standard Interconnection Requirements

Appendix 4. Texas Interconnection Standard Draft

Appendix 5. California Utility Interconnection Standards

(boxed in separate container)

Appendix 6. California Net Metering and Interconnection Agreement